UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

[redacted]

February 4, 1993

MEMORANDUM FOR: The Chairman
Commissioner Rogers
Commissioner Curtiss
Commissioner Remick
Commissioner de Planque

FROM: James M. Taylor
Executive Director for Operations

SUBJECT: RESULTS OF THE NRC SENIOR MANAGEMENT MEETING HELD JANUARY 26-28, 1993

The purpose of this memorandum is to provide the Commission with (1) a summary of discussions held at the January 26-28, 1993 NRC Senior Management Meeting, (2) copies of letters to be sent to the licensees of plants on the problem plant list that will be discussed at the February 9, 1993 Commission meeting, and (3) copies of letters to be sent to plants selected as good performers in accordance with the pilot program described in SECY-91-103.

As the Commission is aware, NRC senior managers meet approximately biannually to review the performance of operating nuclear power plants licensed by the NRC. These meetings are conducted to assure NRC is focusing its resources on plants and related issues of greatest safety significance.

Nuclear power plant performance was a major topic of discussion at this latest NRC Management Meeting. A summary of the results of this discussion is presented in Enclosure 1. This meeting was extended to three days to permit discussion of major topics of interest of all NRC offices.

On the morning of February 5, 1993, the staff will transmit by facsimile the letters in Enclosure 2 to the chief executive officers of the plants in Categories 1, 2, and 3 informing them of the staff's assessment of their plants and of the February 9, 1993 Commission meeting. In addition, the staff plans to telephone each of these licensees on February 5, 1993 to discuss the basis for the conclusions made by the NRC senior managers. The time of these notifications is provided to give licensee management an opportunity to attend the Commission meeting if they should so choose. Also, on February 5, the letters in Enclosure 3 will be sent to the licensees of those plants identified as good performers. Enclosure 4 is a draft summary of the January 26-28, 1993 NRC Senior Management Meeting, and Enclosure 5 is a list of attendees at that meeting.

[redacted]

D17

[redacted]

Please note that the information contained with this memorandum is sensitive and will be first discussed publicly at the February 9, 1993 Commission meeting.

Following the meeting, letters to licensees will be placed in the Public Document Room.

Original Signed By:
James M. Taylor
James M. Taylor
Executive Director
for Operations

SOUTH TEXAS PROJECT 1 and 2

This was the second time South Texas Project (STP) was discussed at the SMM. South Texas was previously discussed at the January 1991 SMM. South Texas Project has had declining performance during the past two SALP periods, stemming mainly from weaknesses in material condition and housekeeping, human performance, and organizational performance.

The poor material condition of the plant is attributed to: (1) the age of the equipment, (2) lack of preventive maintenance of non-Technical Specification equipment, (3) perceived lack of ownership by the Operations Department, (4) weaknesses with work control, planning and scheduling, (5) design problems, (6) poor craft workmanship, (7) lack of engineering support, (8) lack of management and supervisory visibility in the plant, and (9) insufficient resources or ineffective resource allocation in the maintenance area.

Personnel errors are attributed to: (1) inadequate procedures, (2) inattention to detail, (2) miscommunications, (3) lax attitude toward accomplishing work, and (4) inexperienced or poorly trained personnel.

The poor material condition of the plant and the personnel errors have led to trips, transients, engineered safety feature actuations, forced outages and Technical Specification violations.

Over the past two years, several instances of willful violations committed by low-level licensee and contractor personnel were noted. Management and worker morale appears low in some departments and the Plant Operations and Nuclear Training managers recently left the facility, expressing concern to NRC about the management style of senior licensee management. During several 1992 events, station personnel were reluctant to utilize the corrective action system to document known problems, particularly affecting equipment maintenance, and the licensee has identified this as a generic problem area. The failure to initiate corrective action documents for known problems was confirmed during a recent NRC safety team inspection. Potential causes of organizational performance problems include: (1) poor teamwork and communications and (2) ineffective self-assessment.

The licensee instituted an Operational Improvement Plan (OIP) to improve the work environment at the facility and the availability and reliability of the units, but the results have been mixed. Because of these mixed results, station performance has often been cyclic over the past three years, but, overall, a declining performance trend has been discernible. Recently, in a supplemental response to the last SALP report, the licensee recognized performance problems and proposed corrective actions. The overall performance does not warrant placement on the NRC's watch list. However, a Diagnostic Evaluation will be conducted to further understand licensee performance.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

Mr. Zack T. Pate, President
Institute of Nuclear Power Operations
700 Galleria Parkway
Atlanta, GA 30339-5957

Dear Mr. Pate:

Enclosed for your information is a copy of the Diagnostic Evaluation Team report for the South Texas Project Electric Generating Station. This evaluation was initiated following discussions during the NRC senior managers meeting in January 1993. The need for a diagnostic evaluation was based on a perceived decline in the licensee's performance at South Texas Project. The report documents the team's findings and conclusions, and includes discussions of the licensee's strengths and weaknesses.

I would be pleased to provide any clarification or further information, if desired.

Sincerely,

James M. Taylor
Executive Director
for Operations

Enclosure:
Diagnostic Evaluation Team report
South Texas Project Electric Generating Station

cc w/o encl:
Sam Newton, INPO

D/1

Mr. Zack T. Pate, President
Institute of Nuclear Power Operations
700 Galleria Parkway
Atlanta, GA 30339-5957

Dear Mr. Pate:

Enclosed for your information is a copy of the Diagnostic Evaluation Team report for the South Texas Project Electric Generating Station. This evaluation was initiated following discussions during the NRC senior managers meeting in January 1993. The need for a diagnostic evaluation was based on a perceived decline in the licensees performance at South Texas Project. The report documents the team's findings and conclusions, and includes discussions of the licensee's strengths and weaknesses.

I would be pleased to provide any clarification or further information that you may require.

Sincerely,

James M. Taylor
Executive Director
for Operations

Enclosure:
Diagnostic Evaluation Team report
South Texas Project Electric Generating Station

cc w/o encl:
Sam Newton, INPO

Distribution w/o encl:

AEOD R/F	ELJordan	RLSpessard	EDO r/f	MTaylor
DOA R/F	DFRoss	SRubin	JMTaylor	
File D912	CWHehl	DCS	JSniezek	

OFFICE:	RI	D:DOA:AEOD	DD:AEOD	D:AEOD	EDO
NAME:	CWHehl	RLSpessard	DFRoss	ELJordan	JMTaylor
DATE:	06/ /93ms	06/ /93	06/ /93	06/ /93	06/ /93

OFFICIAL RECORD COPY H:PATE.STP

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

The Honorable Ann W. Richards
Governor of Texas
Austin, Texas 78771

Dear Governor Richards:

I appreciate the interest that you have expressed about the NRC's ongoing Diagnostic Evaluation of the South Texas Project. The Diagnostic Evaluation will provide an independent assessment of HL&P's performance at South Texas, and the results of this effort will supplement information from the NRC's Systematic Assessment of Licensee Performance (SALP) and Performance Indicator programs, and other assessment data.

The NRC's decision to conduct a Diagnostic Evaluation at South Texas resulted from a January 1993 meeting of NRC senior managers, where a detailed review of the regulatory and operational performance history of the South Texas Project, as well as other licensed nuclear facilities, was conducted. During these discussions, it was concluded that additional information regarding South Texas would be needed for NRC senior management to more fully evaluate overall plant performance.

At this juncture the Diagnostic Evaluation Team (DET) has completed the initial two weeks of its onsite evaluation work and two weeks of additional evaluation work away from the site. It will complete the last part of the onsite evaluation work during April 26-30, 1993. The team's plan calls for the DET Report to be issued in mid-June 1993. Thus, the DET results will be available for consideration by NRC senior management when they meet again in June 1993. At that time, they will review the regulatory and operational performance history of South Texas, as well as other licensed nuclear facilities. As with the NRC's normal inspection practices, should the team identify an issue of immediate safety concern it would be promptly handled by the NRC Region IV Office.

On April 7, 1993, during the initial onsite evaluation period, the DET manager met with the City of Austin Utility Council and provided an overview of the Diagnostic Evaluation process and the team's evaluation plan. At this meeting, he indicated that the NRC would conduct a public meeting in the vicinity of the South Texas Project to discuss the team's results after issuance of their report.

D/2

We will, of course, provide you with a copy of the South Texas DET Report and will inform Roger Mulder and Susan Rieff of your staff of our plans for the public meeting when they are finalized.

Sincerely,

Ivan Selin

We will, of course, provide you with a copy of the South Texas DET Report and will inform Roger Mulder and Susan Rieff of your staff of our plans for the public meeting when they are finalized.

Sincerely,

Ivan Selin

DISTRIBUTION:
JTaylor, EDO
JSniezek, EDO
MTaylor, EDO
HThompson, EDO
JBlaha, EDO
EJordan, AEOD
TEMurley, NRR
JMilhoan, RIV
CKammerer, OSP
DRoss, AEOD
RLSpessard, AEOD
SRubin, AEOD
HBailey, AEOD
EDO 8795
AEOD R/F
DOA R/F
AEOD 93-32
SECY (CRC-93-0323)

*See previous concurrence

OFFICE:	D:DOA:AEOD	AEOD:DD	AEOD:D	EDO	EDO
NAME:	LSpessard*	DRoss	EJordan	JSniezek	JTaylor
DATE:	04/26/93	04/ /93	04/ /93	04/ /93	04/ /93
OFFICE:	C:NRC				
NAME:	ISelin				
DATE:	04/ /93				

OFFICIAL RECORD COPY DOCUMENT NAME: GRNT.TCK

CROSS REFERENCE
OF
NRC DIAGNOSTIC EVALUATION TEAM
REPORT ON STP
TO
STP BUSINESS PLAN
AND
HL&P OPERATIONAL READINESS PLAN

D/3

INTRODUCTION

The Business Plan and the Operational Readiness Plan (ORP) provide STP's response to the root causes and specific findings and observations contained in the NRC's Diagnostic Evaluation Team (DET) Report of June 10, 1993. The following matrix shows which Business Plan and ORP elements address the various DET Report findings and observations. References to the Business Plan are by Focus Area Initiative Action Plan number designations (example: C5.1) and to the ORP by section and paragraph designations (example: V.B.1.a) and by the Action Summary designations (example: ORP 51). As illustrated by the matrix all of the DET findings have been or are being addressed. Following the matrix are indexes for the Business Plan Focus Area Action Plans and for the ORP section headings.

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
2.1.1 Marginal Staffing for Scope of Responsibility			**Operations**
a. The shift supervisor spent the majority of his time performing a number of administrative duties, including reviewing work packages for work start authority and again at closeout for post-maintenance test adequacy.	6	C 5.1 C 5.2 D 1.1 D 5.1 D 5.2 D 5.4 D 5.5 F 6.1	V.B.1.a V.B.1.b V.B.2.b ORP 51, 52
b. The team confirmed through interviews that there was a heavy administrative burden placed on the shift supervisors during power operation. This situation was exacerbated during refueling outages.	6	C 5.1 C 5.2 D 1.1 D 4.2 D 4.3 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5	V.B.1.b ORP 51, 52
c. Additionally, the team observed that the shift supervisor was routinely involved in providing the maintenance craft personnel with general information, such as plant status and schedules, that could have been obtained elsewhere.	6	C 5.1 C 5.2 D 1.1 D 4.2 D 4.3 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5	Not Applicable
d. The surveillance test program was also a significant resource burden on the control room staff in general and the SROs in particular. Each unit has three-trains of safety equipment, thus adding a third more surveillance than the conventional two train design.	6	C 5.1 C 5.2 D 1.1 D 4.2 D 4.3 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5 D 6.1 D 6.2	V.B.1.a V.B.1.b ORP 51, 52
e. Operations, in lieu of the instrumentation and control department, conducted the solid state protection system (SSPS) logic surveillance that essentially consumed the entire control room staff. Shift supervisors stated that during these tests, it was sometimes necessary for them to become directly involved in collecting test data.	6	C 5.1 C 5.2 D 4.2 D 4.3 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5 D 6.1 D 6.2	Not Applicable
f. In addition, with the implementation of the reactor trip reduction program, SROs were expected to assume a more active oversight role during certain critical surveillance. This program was a good initiative, but was implemented without regard to the accompanying resource burden.	6	C 5.1 C 5.2 D 4.3 D 5.1 D 5.2 D 5.3 D 5.4	V.B.1.b ORP 51, 52
g. The work control program, including post-maintenance testing (PMT) and equipment clearance orders, had evolved to become cumbersome and labor intensive.	6	D 1.1 D 2.1 D 5.1 D 5.2 D 5.3 D 5.4 F 6.1	V.B.1.b V.C.7 V.B.2.b ORP 87
h. The limited operational experience throughout the site organization placed an excessive reliance on the shift supervisor to screen work packages for safety impact and selection of appropriate PMT.	6	A 2.1 C 5.1 C 5.2 D 4.2 D 4.3 D 5.1 D 5.2 D 5.3 D 5.4 F 6.1	V.A.3 V.B.1.b ORP 49
i. The three train design requirements and the history of material condition problems frequently prompted the control room staff to cause the plant to enter limiting conditions for operation (LCO). ... On the basis of a request by the team, the licensee performed a survey and concluded the plant entered LCOs at a rate greater than four times that of similar facilities.	7	D 5.1 D 5.2 D 5.4 D 6.1 D 6.2	III.B.1 III.C.3 III.B ORP 13, 14, 22, 23
j. The licensee further strained staffing levels for the non-licensed reactor plant operators (RPOs) by implementing 12-hour shifts without margin above the administrative staffing limit of 4 each shift. Thus, any delay in an RPO reporting to work resulted in holding one of the onshift RPOs over past the normal 12-hour shift and therefore, on occasion, exceeding the technical specification (TS) overtime guidelines.	7	C 5.1 C 5.2 D 5.2 D 5.3 D 5.4	V.B.1.a ORP 51, 52

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
k. The RPOs were significantly affected by degraded equipment and balance of plant workarounds.	7	D 5.2 D 5.4 D 5.5 F 1.1 F 3.1	III.B III.C ORP 13, 14, 19 - 21, 24 - 25
l. RPO logkeeping rounds were being conducted on an expedited basis to accommodated management's expectation to keep work moving. Numerous examples of frayed insulation and oil leaks were left unchallenged by the RPOs.	7	A 1.1 C 5.1 C 5.2 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5	Not Applicable
m. The shortage of RPOs resulted from the decisions management made ... to reduce the operator training pipeline size and frequency, as well as to staff an operations support activity with reactor operators (RO) and RPOs in lieu of outside contractors.	7	C 5.1 C 5.2 D 4.1 D 4.2 D 4.3 D 5.2 D 5.4 D 5.5	V.B.1.a ORP 51, 52
n. Additionally, management recently decided to relax the standards for staffing a crew to allow the use of apprentice RPOs as long as there were qualified at their specific watchstations. These management decisions could continue to impact plant performance because of the need to utilize seasoned RPOs to fill the upcoming reactor operator license class, thus further reducing the skill level of the remaining RPOs in the field.	7	C 5.1 C 5.2 D 4.1 D 4.2 D 4.3 D 5.2 D 5.3 D 5.5	V.B.1.a ORP 51, 52
o. The additional workload associated with the dual unit outages had forced the licensee to defer operator training and reduce the shift rotation from five to four crews. Personnel from the extra crew that would normally be in training were dispersed into remaining crews to support the outages. Training personnel stated the proposed schedule to resume training would reduce the scope of requalification training to include only the minimum required subjects.	7	C 5.1 C 5.2 D 4.1 D 4.2 D 4.3 D 5.2 D 5.4	Not Applicable
p. In addition, the licensee had suspended on-the-job RPO training since February 18, 1993, to correct performance issues relating to the role of the evaluators. An attempt to retrain evaluators, both in an initial one day class and subsequent series of classes, failed in part because operations could not divert individuals away from their plant duties to attend.	7	C 5.1 C 5.2 D 4.1 D 4.2 D 4.3 D 5.2 D 5.4 D 5.5	Not Applicable
q. The team reviewed the staffing requirements to mitigate a resource-intensive accident (reactor shutdown outside the control room) and concluded that the existing staffing would be significantly strained to handle such a scenario.	8	C 5.1 C 5.2 D 5.2 D 5.4	V.B.1.a ORP 51 , 52
2.1.2 Poor Support to Operations			**Operations**
a. Absence of permanently-installed flow measuring devices required the use of temporary test instrumentation to support routine pump flow surveillance in safety-related systems such as the essential chilled water, auxiliary feedwater, RHR, and spent fuel cooling systems. Extended surveillance setup times had been necessary to obtain accurate and meaningful surveillance results.	8	A 4.1 A 4.2 D 5.2 F 3.1	III.D.8 ORP 37 - 39
b. Numerous Target Rock solenoid valves (SOVs) exhibited problems due in part to installation in high temperature applications. Some of the problems resulted in the SOVs being out of their required position or without proper remote indication. Operators obtained local readings and measurements to compensate for these inadequacies and performed contingency actions to operate these valves properly. Systems where these SOVs were installed included the primary sample system the steam generator bulk water sample system, the chemical volume and control system, and the reactor vessel head vent system.	8	A 4.1 A 4.2 F 3.1	III.D.6 ORP 35

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
c. Numerous automatic controls, such as temperature control valves (TCVs), had been inoperable for a significant period of time. Examples included the TCVs in BOP lube oil coolers, the seal oil coolers, and the hydrogen coolers on the turbine generator. These TCVs were oversized and had to be manually throttled, along with the associated bypass valves, in order to control cooling for the various systems.	8	A 4.1 A 4.2 D 5.2 F 3.1	III.D.5 ORP 34
d. The Information Resources Organization supplied the operations staff with programs, such as a TS Action Statement Program, which it could not use because they did not perform the required tasks and were difficult to use. As a result, operations developed an internal network of computer information systems and software programs that aided in performing such functions as work control, equipment clearances, and reactor coolant system leak rate calculations [also operability tracking]. ... These systems were initially developed without appropriate quality assurance controls and procedural guidance. The team reviewed the licensee's actions to date and found these computer systems still lacked quality controls regarding software development and utilization.	9	D 3.3 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9	V.B.1.b (4) ORP 55
e. The licensee had not aggressively pursued TS revisions to resolve the numerous inconsistencies within the TS at STP. The licensee has written approximately 150 technical specification interpretations (TSIs) and clarifications (TSCs) to help clarify some of these TS inconsistencies.	9	D 6.1 D 6.2	Not Applicable
2.1.3 Confusing and Conflicting Management Expectations			**Operations**
a. Management has sent confusing and conflicting guidance to the control room staff through numerous memoranda without soliciting input from the first line supervisors. Some of this guidance consisted of the implementation of operations policies and standards and other informal guidance. Many of these informal memoranda were revisions or changes that sometimes contradicted earlier memoranda. ... The licensee attempted to consolidate their written guidance to the control rooms into a "Plant Policies and Procedures Manual". This effort appeared to have been hampered by the inability of the licensee to determine the extent and subject matter of the memoranda that had been issued.	9 10	A 1.1 B 3.1 D 2.1 D 5.4 D 5.5 D 6.1 D 6.2 D 8.1	V.C.9
b. Program and policy implementation was ineffective, in part, because of a lack of operations perspective and middle management involvement. ... The reactor trip prevention program was implemented without being explained sufficiently to be uniformly understood and accepted. Management's desire to reduce trips by deferring more work to the outage, while at the same time not providing additional resources or extending the outage duration, appeared as a conflicting message to the control room staffs.	10	A 1.1 B 3.1 D 2.1 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5	Not Applicable
2.1.4 Inconsistent Operator Performance			**Operations**
a. No SRO was in the Unit 2 control room for a short period of time because the unit supervisor left the control room to participate in a surveillance activity. The licensee determined the root cause to have been a lack of self-verification and deficiencies in management guidance regarding command and control. Contributing factors included the relative inexperience of the SROs involved, shift rotation, and competing tasks that called the unit supervisors out of the control room.	11	C 5.1 C 5.2 D 4.1 D 4.2 D 4.3 D 5.4 D 5.5	Not Applicable
b. An inadvertent boron dilution event occurred while the operators attempted to borate the reactor coolant system. The licensee determined that the event was caused by a deficient understanding of the system operation during shutdown conditions. However, other contributing factors mentioned in the licensee's assessment included and inadequate shift turnover, insufficient crew experience, and the inability of personnel to properly focus on a specified task.	11	C 5.1 C 5.2 D 4.1 D 4.2 D 4.3	Not Applicable

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
c. During a periodic surveillance of the ECW system, the operator who was performing the local valve manipulation had to leave the area to locate a valve lock key so he could throttle flow to heat exchanger. When he returned, he throttled the valve to the wrong heat exchanger in a different train. The licensee determined that the event resulted in part from inadequate self verification. The licensee stated that a contributor to the event was the insufficient number of personnel available to perform the evolution. SROs who have performed this surveillance in the past stated to the team that generally, four RPOs are required to perform this surveillance, although the surveillance could have been performed efficiently with three RPOs. In this case, only two RPOs performed this surveillance which made it difficult to focus on the required specific tasks. The three remaining RPOs on shift at the time were not available because they were performing other duties.	11	C 5.1 C 5.2 D 4.1 D 4.2 D 4.3 D 5.2	V.B.2.d
d. Weaknesses in the PMT program, such as difficulties in understanding the PMT reference manual, have resulted in confusion and differing interpretations by the various users. As a result, the PMT recommendations from the planners were often very broad and vague. This contributed to the performance of incorrect post-maintenance testing following painting activities on SDG 13.	12	D 1.1 D 2.1 D 4.2 D 4.3 F 6.1	V.C.7 ORP 87
e. Poor procedures contributed to two occasions in which an RHR pump tripped on low flow. One of these trips occurred during a reactor cavity draindown.	12	D 2.1 D 4.2 D 4.3	Not Applicable
f. An operating crew shifted from charging pump 1B, which was operable, to charging pump 1A, which was inoperable, because they did not thoroughly review a work package for closure. In this case, two maintenance groups were performing work activities associated with pump 1A. One group had completed its work and had sent its package to the control room, the other had not. There was no easy way to determine the status of work being performed.	12	D 1.1 D 4.2 D 4.3 D 5.5	Not Applicable
g. The team generally agreed with the licensee's assessment that there were two fundamental factors for the events in 1992 and early 1993: (1) personal accountability and responsibility needed to be emphasized, stressing self-verification and attention to detail and (2) organizational and programmatic support had to be strengthened to enhance the clarity of written guidance, oral briefings and instructions, equipment design and labeling, and repetitive task assignments. However, the team considered that work schedule, work practices and staffing issues have also been significant contributors to past events. These were only recently being considered as contributory causes by the licensee.	12	C 5.1 C 5.2 D 1.1 D 2.1 E 2.1 E 3.1	V.B.2 d
2.1.5 Ineffective Problem Identification and Resolution			**Operations**
a. The procedure for performing the operations' self-assessment program appeared to provide a good, detailed methodology. However, in implementing this procedure, the operations staff performed shallow assessments that were relatively ineffective in identifying program weaknesses.	12	D 4.3 E 2.1 E 3.1	Not Applicable
b. Evaluations of operational events, both by operations and other organizations, were of limited depth and did not always consider the broader implications and impact on the plant.	13	E 1.1 E 1.2 E 1.3 E 1.4 E 2.1	V.C.1 ORP 78
c. In followup to a Unit 1 inverter trip on March 29, 1993, the corrective actions group (CAG) focused on several narrow elements of the event such as the RPO energizing the cabinet without a procedure in hand. However, the CAG did not address other generic aspects of the event, such as the adequacy of the recovery actions and the RHR system controls automatically swapping to the remote shutdown panel.	13	E 1.1 E 1.2 E 1.3 E 1.4 E 2.1	V.C.1 ORP 78

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN		ORP
d. Two performance problems reviewed by the team concerned the return of essential chiller 21A to service without proper paperwork being completed and failed to verify control rod position between digital rod position indication and demand position. The operations staff determined that the root causes were inattention to detail and human performance problems, respectively. Recommended corrective actions focused on counseling the individuals or issuing memoranda to the operators. However, the more fundamental aspects of these events, including weaknesses in the work control process and distractions in the control room, were not pursued. Discussions with applicable operations personnel indicated that they were aware that more fundamental issues existed; but did not have the time or charter to pursue further.	13	D 1.1 D 5.5 E 1.2 E 1.4	D 5.2 E 1.1 E 1.3	V.B.2.d V.C.1 ORP 78
e. The two SPR coordinators on the operations staff were responsible for performing 8 to 10 OER and 20 to 30 SPR reviews a month. These individuals spent large amounts of overtime to complete the sizable workload as the volume of SPRs continued to grow.	13	C 5.1 D 5.2 D 5.4 E 1.2 E 1.4	C 5.2 D 5.3 E 1.1 E 1.3 E 4.1	V.C.1 ORP 78
f. Management support to correct program and component problems was not always effective. This was evidenced by management deferral of corrective action proposals to fix several longstanding problems.	13	A 1.1 A 4.2 D 5.5 E 1.2 E 1.4	A 4.1 C 4.1 E 1.1 E 1.3	Not Applicable
g. The operators continually faced challenges such as poor plant labeling, ... Poor component labels contributed to numerous plant transients and other events. In response to a 1991 NRC concern, the licensee stated that a labeling improvement program was being implemented, and committed to reconsider the direction and schedule for the program. ... At the end of the evaluation (DE) the licensee informed the team that it was again reviewing the prioritization of the plant labeling upgrade.	13	See ORP		V.C.2 ORP 79, 80
h. The operators continually faced challenges such as a weak locked valve program.	13	See ORP		V.C.3 ORP 81
i. The operators continually faced challenges such as difficulty in controlling plant cooldown after a reactor trip.	13	F 1.1 F 4.1	F 3.1	Not Applicable
j. Additionally, to reduce waterhammer in the auxiliary feedwater (AFW) system, the operators had to control AFW flow to the steam generators with a stop check valve. Management did not properly address this problem until after the thermal cycles on the steam generator from this method of flow control became an issue.	13	A 4.1 D 5.5	A 4.2 F 3.1	Not Applicable
2.2.1 Ineffective Corrective Maintenance				**Maintenance and Testing**
a. The licensee had established a program to determine the root cause of events and major equipment failures but the identification and evaluation of maintenance issues did not always occur.	15	D 5.2 E 1.2 E 1.4 F 3.1	E 1.1 E 1.3 E 2.1	V.C.1 ORP 78
b. Though the procedures in many cases did not help alert workers to potential problems, a well trained, qualified, attentive workforce could have successfully completed the tasks.	15	D 2.1 D 4.3	D 4.2 E 3.1	V.B.2.a V.B.2.e ORP 60

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
c. A feedwater isolation bypass valve (a containment isolation valve) was found partially open for over a year. Maintenance had been performed on the valve to correct a failure to get a closed indication light in the control room. Maintenance personnel stroked the valve several times and then adjusted the closed limit switch to bring in the closed light without confirming the actual position of the valve. Five months later the licensee issued another SR to correct an apparent discrepancy between the control room indication and the local position indication. However, the potential safety significance of this condition was not properly recognized and the SR was worked six months later. At that time maintenance personnel determined the valve was only going 75% closed.	15	E 1.1 E 1.2 E 1.3 E 1.4	Not Applicable
d. Standby diesel generator (SDG) injector pump hold down studs failed on nine separate occasions. The root cause analysis was shallow and corrective actions were insufficient to preclude recurrence. The licensee did not perform a more detailed analysis of the stud failures until the team became involved.	15	E 1.1 E 1.2 E 1.3 E 1.4 E 2.1 E 4.2 F 3.1	V.C.1 ORP 78
e. A SDG jacket water leak took four attempts to correct. The first two repair efforts were unsuccessful because maintenance personnel installed the wrong size of gasket. In a third repair attempt, the gaskets were made on site with material not suited for that application.	16	D 4.2 D 4.3 E 2.1 E 3.1 F 5.1 F 5.3	V.B.2.e ORP 60
f. Corrective maintenance performed on the high head safety injection (HHSI) pump damaged the motor when too much oil was added. The oil level sight glass was reinstalled upside down resulting in a higher level mark on the sight glass. The procedure specified 11 quarts as the capacity of the bearing reservoir. Due to the unrecognized reversed level sight glass, maintenance personnel added 20 quarts of oil to obtain the level mark on the sight glass. The result was oil intrusion into the motor windings.	16	D 4.2 D 4.3 D 5.5 F 5.2	Not Applicable
g. Repeatedly, the overspeed trip tappet of a turbine driven auxiliary feedwater pump (TDAFWP) did not return to its normal position after a manual or overspeed trip. The initial corrective action involved removing a sticky tar-like substance from the tappet and the upper turbine housing. Personnel did not determine the cause of the tar-like substance and took no action to preclude its recurrence. Approximately six months later the tappet stuck again in its tripped position when the turbine was manually tripped.	16	D 4.2 E 1.1 E 1.2 E 1.3 E 1.4 E 2.1 F 3.1	Not Applicable
h. In 1989, the windings of a motor-operated valve, critical in establishing hot leg recirculation following a LOCA, electrically shorted rendering the valve inoperable. The licensee performed an inadequate root cause analysis and did not rectify the problem. In 1993, the windings shorted again rendering the valve inoperable.	16	D 4.2 E 1.1 E 1.2 E 1.3 E 1.4 E 2.1 F 3.1	V.C.1 ORP 78
i. In August of 1992, the licensee discovered that seismic hold down screws in the Qualified Display Processing System (QDPS) card racks were missing but did not issue an SR to replace the missing screws for four months. The team noted that the SR had not been implemented or evaluated for operability. At the request of the team the licensee evaluated the situation. Consequently, QDPS was declared inoperable affecting both units.	16	C 5.1 C 5.2 D 4.2 E 1.1 E 1.2 E 1.3 E 2.1 F 1.1	Not Applicable
j. The steam generator primary side access covers on Unit had 1 known leak for two and a half years prior to being repaired. On four separate occasions licensee personnel noted the leaks, however, corrective action was not implemented. These leaks existed through two refueling outages. While numerous SRs were written for repairs, confusion concerning the status of the SRs resulted in the repair efforts not being performed.	16	A 4.1 A 4.2 C 5.1 C 5.2 E 1.1 E 1.2 E 1.3 F 1.1	Not Applicable

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
k. Failure to assess the safety impact of a steam leak and properly prioritize the repair effort resulted in an inoperable steam generator power operated relief valve (PORV). The steam was impinging on the PORV actuator but was not immediately repaired. Having observed previous failures of the FWIVs, caused by degraded hydraulic fluid, the licensee knew that subjecting hydraulic fluid to high temperatures would cause it to degrade. Eventually, the oil degraded preventing the PORV from operating, and it was declared inoperable. After repair efforts failed, the licensee entered and 8-day forced maintenance outage.	16	E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	Not Applicable
l. There was a large maintenance backlog of security system components such as rusted camera base plates, water in manholes, broken doors, and degraded intrusion detection systems. An average of 13 officers, each working 12 hour shifts were being scheduled to compensate for long term maintenance issues.	17	E 1.1 E 1.2 E 1.3 E 1.4 E 2.1 F 1.1 F 3.1	III.B ORP 13 - 21
m. A number of components in the inservice test program were in the alert and failed condition. Seven had been in the alert condition since 1989 without effective corrective action taken. Eleven components had been in the alert range before failing and being declared inoperable. Also, the increased testing frequency for items in the alert range from quarterly to monthly resulted in another burden on operators to accomplish testing.	17	C 5.1 C 5.2 E 1.1 E 1.2 E 1.3 E 1.4 F 1.1 F 3.1 F 4.1	III.D.7 ORP 36, 85, 86
2.2.2 Less than Fully Effective Preventative Maintenance Program			**Maintenance and Testing**
a. In developing the initial PM program before plant licensing, the licensee identified approximately 33,000 PM tasks. In the late 1980's the licensee revise the program to include approximately 11,000 "active" tasks, 12,000 "inactive" (no longer scheduled) tasks, and the remaining tasks either cancelled or superseded. The licensee selected the inactive tasks based on "importance factors: that had been assigned to the individual PM activities when they were developed. After the "importance factors" screening the only review performed to determine which individual PM tasks would be classified as inactive or active, was a non-technical one by maintenance personnel. As a result of not performing these inactive PM tasks, ..., preventable events, equipment failures, and instances of poor assurance of operability (mostly dealing with instrument calibration) occurred.	17	F 4.2	V.C.4 ORP 82, 83
b. Appropriate PM tasks were not developed or included in the PM program for some important equipment in the SDGs and support systems. Relay failures in the voltage-regulating circuit caused inoperable SDGs on two different occasions. The relays had never been replaced nor scheduled to be replaced. Main control board meters used during SDG testing and SDG monitoring were not in the PM program and had not been calibrated since startup. In reviewing the issue of noncalibrated SDG meters the licensee identified approximately 150 additional main control board instruments the were not in the PM program. Some of these instruments monitored important parameters for the 125 VDC batteries and the battery chargers.	18	F 4.2	V.C.4 ORP 82, 83
c. Incomplete or incorrect PM procedures resulted in poor equipment performance. Examples of equipment failures, malfunctions or inoperable equipment resulting from procedural deficiencies were: 1) Repeated examples of 13.8 KV breakers failing to cycle due to inadequate PM lubrication instructions; 2) An ESF actuation from an improperly calibrated emergency cooling water transmitter because the PM instruction did not specify the type of M&TE equipment to be used. The improperly calibrated transmitter contributed to the ESF actuation; and 3) Two relief valves having incorrect setpoints because the PM procedures specified the wrong setpoint.	18	D 2.1 F 4.2	V.C.4 ORP 82, 83
d. The method for improving the PM program involved the use of PM "feedback" forms to identify errors and refinements for incorporation into the program. However, since 1991 a large backlog of PM feedback forms had accumulated. In 1992 over 2500 feedback forms were not processed on schedule. As of April, 1993 the backlog of unprocessed PM feedback forms was approximately 5800. Recently, the licensee added personnel to address this large backlog.	18	D 1.1 F 4.2 F 5.1 F 7.1	III.C.2 ORP 24

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
2.2.3 Maintenance Training Deficiencies			**Maintenance and Testing**
a. In mid-1992, an industry organization determined the licensee's basic maintenance craft skills training program was deficient. In response the licensee established a recertification testing program for journeyman in the three disciplines. To allow continuation of work, craft qualification matrices were established. Each matrix listed individual craftsmen and the tasks in which they were currently "qualified," such as breaker maintenance. To compensate for a lack of "qualified" individuals, a supervisor or qualified journeyman continuously observed the work of the unqualified personnel.	18	D 4.1 D 4.2 D 4.3	V.B.2.e ORP 60
b. The training for molded case circuit breakers did not include the correct method for determining the breaker settings based on the values (amperes) provided in the setpoint document. This lack of training and the complex procedural instructions for determining the breaker settings resulted in incorrect breaker settings rendering seven safety-related components inoperable.	19	D 2.1 D 4.1 D 4.2 D 4.3	III.D.3 V.B.2.e ORP 60
c. I&C technicians introduced air into essential chillers and flooded a control panel with oil due to a lack of understanding of how the chillers function under vacuum. This contributed to degraded equipment performance and lack of equipment operability.	19	D 4.1 D 4.2 D 4.3	V.B.2.e ORP 60
d. Craft personnel were not trained on the need to expeditiously place battery chargers into service after performing discharge testing of 125 VDC station batteries. This lack of training and omission from the testing procedure of this critical element of battery testing could have resulted in permanent damage to the station batteries.	19	D 2.1 D 4.1 D 4.2 D 4.3	V.B.2.e ORP 60
e. Beyond the basic skills training deficiencies, the licensee identified that training in specialized skill did not match the necessary tasks to be performed.	19	D 4.1 D 4.2 D 4.3	V.B.2.e ORP 60
f. The Mechanical maintenance staff was not trained to maintain the TDAFWP governor or the TDAFWP overspeed trip mechanism. This contributed to the numerous unsuccessful attempts to resolve problems on the TDAFWP.	19	D 4.1 D 4.2 D 4.3	III.D.1 V.B.2.e ORP 29, 60
g. Training for reactor coolant pump motors was based on a generic 2000 horsepower motor and did not include the unique features of these motors.	19	D 4.1 D 4.2 D 4.3	V.B.2.e ORP 60
h. Training on the SDGs did not include the governor or voltage regulator.	19	D 4.1 D 4.2 D 4.3	V.B.2.e ORP 60
i. I&C technicians assigned to work on the security system were not trained on certain aspects of that system. Three of the five designated technicians had not received specific security system related training and the other technician received only limited training.	19	D 4.1 D 4.2 D 4.3	V.B.2.e ORP 60
2.2.4 Deficiencies in the Replacement Parts Program			**Maintenance and Testing**
a. The lack of parts caused safety-related equipment to remain inoperable and degraded the performance of equipment important to safety. The lack of readily available parts contributed to the size of the maintenance backlog. ... Numerous general usage material such as bolts, nuts, gaskets, and desiccant were not available as general issue items from the warehouse. To support emergent work, needed items were obtained by substituting parts that were reserved for other planned work.	19 20	D 3.3 D 5.2 D 5.4	V.C.8 ORP 88, 89
b. In December 1992, during maintenance to repair an AFW turbine trip throttle valve, a replacement disc and seat were not available in the warehouse. The valve was reassembled and the system declared operable. This leaking valve contributed to numerous overspeed turbine trips in January and February of 1993.	20	D 3.3 D 5.2 D 5.4	V.C.8 ORP 88, 89

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
c. The lack of spare parts contributed to valves within the primary containment being inoperable for a year. During the 1991 refuel outage, "T" drains were not available for installation into some new valve motors. ... A failure of the work control system later resulted in the "T" drains not being installed in a timely manner.	20	D 5.2 D 5.4 F 6.1	V.C.8 ORP 88, 89
d. The Unit 2 secondary side B PORV was inoperable because of an internal hydraulic leak that caused premature failure of a pressure switch. The internal leak caused the hydraulic pump to cycle frequently and eventually resulted in the high pressure switch failing low. The hydraulic pump ran continuously until its thermal overloads tripped. The switch was replaced but the leak was not fixed because of a lack of parts.	20	D 5.2 D 5.4 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	V.C.8 ORP 88, 89
e. Previously, several switches on the CH system failed and were replaced. However, if they had failed again no replacements were in the warehouse or on order when the inventories were reviewed by the team.	20	D 3.3 D 5.2 D 5.4	V.C.8 ORP 88, 89
f. Occasionally, maintenance personnel installed or attempted to install the wrong part in safety-related systems at the facility. The major reason for these situations appeared to be in the parts sourcing process. The process to determine the correct replacement part was extremely difficult and cumbersome. The computerized parts reference system consisted of two databases requiring the viewing of multiple screens. The overall response of the system was slow. Numerous part numbers were "flagged" for revision because of the large engineering document backlog. Sometimes part numbers, as in some Rockwell valve components, were wrong. ... When computer information was questionable, such as being flagged, design and purchase documentation had to be used. However, a number of these documents had unincorporated revisions due to the large engineering backlog.	20	D 1.1 D 3.3 D 3.6 D 5.2 F 7.1	III.C.3 V.C.5 ORP 25 - 28, 84
g. During repair activities to stop a jacket water leak on the inlet header of a SDG, the discharge header gasket was installed. This occurred twice before the mechanics recognized that the gasket was not the correct size.	20	D 4.2 D 4.3 F 5.1 F 5.3	Not Applicable
h. During repair activities to return an essential chiller to service, the correct type of pressure switch was installed but was not qualified as safety-related [sic]. The switch was replaced before the chiller was placed back into service.	20	D 3.3 D 3.6	Not Applicable
2.2.5 Insufficient Support to Maintenance			**Maintenance and Testing**
a. Maintenance department senior supervisors provided limited reinforcement of expected quality performance standards. Their time was dominated by preparation for meetings, attending meetings, and performing administrative tasks.	21	A 1.1 A 2.1 D 5.1 D 5.2 D 5.4 D 5.5 F 5.2	V.B.2.a ORP 59
b. The staff size was insufficient to accomplish corrective maintenance given the productivity achieved using the existing system, the unique three-train design of the facility, and the untimely resolution of design deficiencies. The balance of plant corrective maintenance effort suffered mostly due to the lack of personnel resources.	21	D 1.1 D 5.1 D 5.2 D 5.4 F 1.1	Not Applicable
c. From the end of the Unit 2 refuel outage (December 1991) until the beginning of the Unit 1 refuel outage (September 1992) both unit were essentially operating at power. However, during these 9 months, the backlog of non-outage SRs increased by 1600, an increase of approximately 50 percent.	21	D 1.1 F 1.1	III.B V.B.2.f V.B.2.g ORP 13 - 21, 62

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
d. Recognized design deficiencies for numerous equipment had not been resolved. Examples included the Brown Boveri breakers for the TSC diesel generators.	21	A 4.1 D 5.2 D 5.4 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	III.C III.D.4 V.B.3 V.B.4 ORP 22 - 28, 32, 33, 63 - 75
e. Recognized design deficiencies for numerous equipment had not been resolved. Examples included the obsolate fire protection computer.	21	A 4.1 D 5.2 D 5.4 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	III.C V.B.1.b(3) V.B.3 V.B.4 ORP 22 - 28, 53, 54, 63 - 75
f. Recognized design deficiencies for numerous equipment had not been resolved. Examples included water intrusion into the startup feedwater pump's lubrication system.	21	A 4.1 D 5.2 D 5.4 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	III.C V.B.3 V.B.4 ORP 22 - 28, 63 - 75
g. Recognized design deficiencies for numerous equipment had not been resolved. Examples included refrigerant and oil contamination mitigation devices had not been permanently installed on essential chillers even though air and moisture intrusion had reduced their reliability.	21	A 4.1 D 5.2 D 5.4 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	III.C III.D.2 V.B.3 V.B.4 ORP 22 - 28, 30, 31, 63 - 76
h. In an outage condition, substantial, routine use of overtime was used to try to accomplish the scheduled tasks. ... In some instances Technical Specification overtime guidelines were exceeded without appropriate management review and approval.	21	A 1.1 C 2.1 C 5.1 C 5.2 D 5.2 D 5.3 D 5.4 D 5.5 F 4.2	V.B.2.c
i. Staffing limitations impaired the amount of vibration monitoring accomplished under the predictive maintenance program.	22	D 5.2 F 4.2	Not Applicable
j. During a vibration analysis in May 1990, the Unit 1 main generator seal oil backup pump exceeded alarm limits. However, over 2 1/2 years passed before the next vibration readings were taken in January 1993. Subsequently, the deteriorated motor and pump bearing had to be replaced.	22	D 2.1 D 5.2 F 4.2	Not Applicable
k. Since the plant began commercial operation the vibration of the Unit 1 HHSI pump motors exceeded the alarm limits of the predictive maintenance program. However, more than 27 months passed between vibration readings on the 1C pump and 18 months passed for the 1A pump. Eventually, unsatisfactory oil samples were taken on the 1A and 1C motor bearings.	22	D 2.1 D 5.2 F 4.1 F 4.2	Not Applicable
l. As much as three years passed between vibration readings on the Unit 1 auxiliary feedwater pumps.	22	D 2.1 D 5.2 F 4.1 F 4.2	Not Applicable
2.2.6 Inefficient Work Control Process			**Maintenance and Testing**
a. The large amount of emergent work significantly contributed to the inefficient work control process. This was due, in part, to the large corrective maintenance backlog which inhibited the timely repair of deficiencies before their condition degraded. ... The excessive amount of emergent work prompted the staff to postpone previously planned or partially planned jobs, adding to the backlog.	22	A 4.1 A 4.2 C 4.1 D 1.1 D 5.2 D 5.4 D 5.5 F 1.1	III.B V.B.2.b ORP 13 - 21
b. A major detractor [in the planning and preparation to accomplish work] was the quality of management information systems.	22	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9	V.C.5 ORP 84

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
c. Planner performance was inhibited, in some cases, by incorrect component identification within the facility on SRs. This necessitated walkdowns of all equipment to verify correct component number against design documents.	23	D 2.1 D 4.2 D 4.3 F 6.1	V.C.2 ORP 79, 80
d. The computer hindered schedular performance because it did not allow for changes in workforce size or show support discipline ties to performing the job.	23	D 3.2 D 3.3 D 3.4 D 3.7 D 5.2 D 5.4	V.C.5 ORP 84
e. The [work] schedule was only published every other day with handwritten updates needed when it was not published.	23	C 4.1	
f. Due to previous training program deficiencies, there were numerous unqualified maintenance personnel requiring increased supervisor observation and direction.	23	D 4.1 D 4.2 D 4.3 D 5.2 D 5.5	V.B.2.e ORP 60
g. Coordination and communication weaknesses contributed to poor maintenance while work package quality and parts availability deficiencies decreased efficiency.	23	B 1.1 D 1.1 D 3.3 D 5.2 F 6.1	V.B.2.a ORP 59
h. During an uncoupled run of the reactor coolant pump, the lower motor bearing failed as a result of lube oil starvation. The starvation occurred when a maintenance worker, attempting to correct a suspect high lube oil level, drained approximately 3 gallons of lube oil before the run. The maintenance worker failed to notify the control room that the lube oil had been drained. The maintenance worker's supervisor, stationed in the control room, stated that he did not know of the suspect high lube oil level and would have stopped the job if he had known that 3 gallons had been drained.	23	D 4.2 D 4.3 D 5.5 F 5.2	Not Applicable
i. Several SDG failures resulted from broken fuel oil injector pump hold down studs, many of which were installed using a deficient stud driver tool designed by the system engineer. The system engineer failed to consult design engineering or the SDG vendor while designing the tool.	23	C 2.1 F 3.1	V.B.3 V.B.4 ORP 63 - 75
j. An inadequate turnover contributed to maintenance personnel flushing two feedwater isolation valve hydraulic systems with used coolant from the balance-of-plant diesel generator instead of the proper flushing fluid.	23	F 5.2	Not Applicable
k. An inadequate pre-job brief contributed to a HHSI motor pump bearing reservoir sight glass being improperly installed. As a result, lube oil was introduced into the motor windings.	23	D 4.2 D 4.3 F 5.2	Not Applicable
l. Coordination of the various support groups did not always occur as evidenced by the team observing two work activities which could not continue because support workers did not erect the designated scaffolding.	23	D 1.1 D 5.4 F 5.1 F 6.1	V.B.1.b (2)
m. Approximately 20 percent of the work packages were revised to correct errors or to change the scope of the work activity.	23	D 1.1 D 4.2 D 4.3 F 6.1	V.B.1.b (2)
n. The work procedures occasionally contained unneeded information and did not match the experience of the individual using the procedures.	23	D 2.1 D 4.2 D 4.3 F 6.1	Not Applicable
o. Procedures were sometimes ignored. ... Contractors testing motor operated valves did not take the procedure to the field or taped all four corners of the 200 plus page procedure shut.	23	A 1.1 D 2.1 D 4.2 D 5.3 D 5.5	Not Applicable
p. When the job required parts not originally anticipated, the parts had to be sourced for availability and usually deallocated from another planned job. However the General Maintenance Supervisor, who had to approve the deallocation, and numerous line supervisors were not sufficiently trained to use the computer which detracted from the parts sourcing effort	23	D 3.3 D 3.6 D 3.7 D 3.9	Not Applicable

too narrow - only computer issue

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
2.2.7 Post-Maintenance Testing Program Not Always Effective			**Maintenance and Testing**
a. The PMT reference manual used by planners to select the appropriate test requirement did not specify appropriate detail and occasionally specified the wrong test.	24	B 3.1 D 1.1 D 2.1 D 5.5 F 6.1	V.C.7 ORP 87
b. The planners lacked appropriate training, experience and guidance that would allow them to compensate for the [PMT reference] manuals deficiencies.	24	D 4.2 D 4.3 D 5.4 F 6.1	V.C.7 ORP 87
c. [Deficiencies in the PMT reference manual and planner experience and training] resulted in planners listing all possible PMT that might be necessary and specifying PMTs to be performed as "if required." This required the already heavily burdened shift supervisor to review the scope of work completed in order to specify the appropriate post maintenance test to be performed.	24	B 3.1 D 1.1 D 4.2 D 4.3 D 5.2 D 5.4 F 6.1	V.C.7 ORP 87
d. Periodically, the shift supervisor selected inappropriate PMT and in some instances inoperable equipment was not identified such as: SDG 13 was inoperable for 2 weeks because of the failure to perform adequate PMT after painting activities. The correct PMT had been specified in the work package but was inappropriately cancelled due to a concern over excessive SDG starts.	24	C 5.1 C 5.2 D 1.1 D 2.1 F 6.1	Not Applicable
e. Periodically, the shift supervisor selected inappropriate PMT and in some instances inoperable equipment was not identified such as: PMT was not performed on a SDG output breaker after a fuel oil injector pump was repaired. During that maintenance activity, the output breaker was racked out to support work on the injector pump and later improperly racked in. For PMT the SDG was started but breaker closure was not tested. During a subsequent surveillance test, the SDG output breaker would not close onto the bus.	24	C 5.1 C 5.2 D 1.1 D 2.1 F 6.1	V.C.7 ORP 87
f. Periodically, the shift supervisor selected inappropriate PMT and in some instances inoperable equipment was not identified such as: After work was performed on the feeder breaker for essential chiller 21C, no PMT was performed, yet the chiller was declared operable. The following day the chiller's feeder breaker tripped during a routine start attempt due to breaker problems.	24	C 5.1 C 5.2 D 1.1 D 2.1 F 6.1	V.C.7 ORP 87
2.2.8 Periodic Testing Not Always Effective			**Maintenance and Testing**
a. Numerous instances had been identified where [surveillance] procedures were inadequate to meet TS surveillance requirements, thereby reducing assurance that the equipment was operable. Among these was a failure to completely test a manual reactor trip handswitch and the nonconservative setting of one of the four reactor protection channels during a reactor startup.	24	See ORP	V.C.6 ORP 85, 86
b. In a followup, the team questioned the licensee concerning an engineering test of the control room emergency ventilation recirculation charcoal adsorbers. Subsequently, the licensee determined the surveillance requirements had not been satisfied in that a defective method had been devised to determine when adsorber testing should be performed. The failure to send the charcoal sample for testing within the required interval resulted in a 3 month delay in determining that the charcoal bed was below required standards for iodine adsorbtion.	25	A 4.1 C 2.1 E 1.1 E 1.2 E 1.3 E 1.4	V.C.6 ORP 85, 86
c. The licensee committed to expand the scope of the enhancement program to meet the original [all surveillance procedures] intent.	25	See ORP	V.C.6 ORP 85, 86
2.3.1 Weak Support in Resolving Plant Problems			**Engineering Support**
a. Examples of ineffective engineering support, investigations, root cause analyses and corrective actions include: The licensee did not determine the root cause of repetitive failures of the fuel injector pump hold-down studs associated with the SDGs. Nine separate failures occurred between 1987 and 1993, including five failures on SDG 22. The failure of these studs was a significant contributor to the high unavailability of SDG 22.	27	E 1.1 E 1.2 E 1.3 E 1.4 E 4.2 F 3.1	V.B.3 V.B.4 V.C.1 ORP 63 - 75, 78

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
b. Examples of ineffective engineering support, investigations, root cause analyses and corrective actions include: The RCAs and accompanying corrective actions were ineffective in preventing repeated failures of the toxic gas monitors and containment ventilation isolation system.	27	E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	V.B.3 V.B.4 V.C.1 ORP 63 - 75, 78
c. Examples of ineffective engineering support, investigations, root cause analyses and corrective actions include: Widespread, longstanding problems with the application and performance of Target Rock solenoid-operated valves (SOVs) were not resolved. These valves were used extensively in several safety-related systems. ... Temporary modifications were installed to bypass containment isolation valves to allow steam generator sampling. Previous corrective actions, such as re-orienting the main steam isolation valve above the seat drains, did not prevent additional failures.	27	A 4.1 E 1.1 E 1.2 E 1.3 E 1.4 E 4.1 F 3.1	III.B.6 V.B.3 V.B.4 V.C.1 ORP 35, 63 - 75, 78
d. Examples of ineffective engineering support, investigations, root cause analyses and corrective actions include: The licensee started up with a significant design deficiency that resulted in excessive water hammer in the auxiliary feedwater system. Engineering's resolution to the issue was to install mechanical stops on the AFW valves to prevent them from closing, which created additional operational concerns. Operators could no longer effectively throttle valves during certain plant conditions to control flow to the steam generators. As a result, operators controlled flow by cycling the stop check valves, resulting in an excessive number of thermal cycles on steam generator nozzles.	27	C 2.1 C 3.1 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	V.B.3 V.B.4 ORP 63 - 75
e. Examples of ineffective engineering support, investigations, root cause analyses and corrective actions include: Corrective actions for numerous safety and nonsafety related circuit breaker problems were not aggressive or complete. The licensee evaluated each breaker failure and took corrective actions for safety-related circuit breakers. Many of these actions were incomplete. Further, the licensee was slow in resolving problems and taking corrective actions for many nonsafety-related breakers.	27	C 2.1 C 3.1 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	V.B.3 V.B.4 ORP 63 - 75
f. Examples of ineffective engineering support, investigations, root cause analyses and corrective actions include: After a reactor trip, the startup feedwater pump (SUFP) failed to start upon demand because of low oil pressure. Repeated occurrences of moisture intrusion had caused the oil filters to be clogged, reducing the lube oil pressure. A previous SUFP trip on low lube oil pressure had not been properly evaluated, resulting in the failure to recognize design deficiencies.	27	C 2.1 C 3.1 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	V.B.3 V.C.1 V.B.4 ORP 63 - 75, 78
g. Examples of ineffective engineering support, investigations, root cause analyses and corrective actions include: During oil pump transfers, the steam generator feed pump turbine tripped repeatedly because the oil pressure decreased rapidly. Engineering mistakenly accepted the recommendation of a vendor to drill holes in the pump casing to prevent air binding, which, when implemented, exacerbated the problem.	27	C 2.1 C 3.1 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	V.B.3 V.B.4 ORP 63 - 75
h. Examples of ineffective engineering support, investigations, root cause analyses and corrective actions include: The Technical Support Center diesel generator was not reliable, as evidenced by repeated failures to start and load during testing. Contributing to the poor reliability was exposure to the environment, design weaknesses, and poor circuit breaker reliability. The licensee only partially implemented proposed resolutions to these problems.	28	C 2.1 C 3.1 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	III.B.4 V.B.3 V.B.4 V.C.1 ORP 32, 33, 63 - 75, 78
i. The engineering staff did not always adequately evaluate equipment operability as illustrated below: In August 1992, a system engineer discovered that seismic hold-down screws were missing from the Unit 1 quality display parameter system (QDPS) card racks, but did not understand the seismic consequences and did not request an evaluation for operability. The licensee did not properly evaluate the effect of the deficiency on operability until so requested by the team in April 1993. The QDPS was subsequently declared inoperable.	28	C 2.1 E 1.1 E 1.2 E 1.3 E 1.4	V.B.3 V.C.1 ORP 63 - 72, 78

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
j. The engineering staff did not always adequately evaluate equipment operability as illustrated below: Torque measurements and computations associated with testing of motor operated valves were not evaluated to verify valve operability. The licensee discovered, upon evaluating previous test data, that several residual heat removal valves had been torqued above design values because of a deficiency in the test procedure and associated engineering documents to measure or compute torque.	28	C 2.1	V.B.3 V.B.4 ORP 63 - 75
k. The installation of plant modifications to effect plant improvements was not always successful.	28	B 1.1 C 3.1 E 2.1	V.B.3 V.B.4 ORP 63 - 75
l. TMs were not thoroughly evaluated and were not aggressively pursued to closure as illustrated in the following: Sixteen TMs were installed for more than 2 years, including some that cause problems for operators. Some TMs were originally assigned a long restoration period (1 to 2 years) or given an extension without adequate justification. Some were later converted to permanent modifications and remained open until the permanent modifications were closed.	28	A 1.1 A 4.1 A 4.2 C 3.1 D 5.2 F 3.1	III.C.3.a V.B.3 V.B.4 ORP 25, 63 - 75
m. TMs were not thoroughly evaluated and were not aggressively pursued to closure as illustrated in the following: In performing engineering evaluation for TMs affecting the CH system and steam generator sample valves, the engineering staff failed to realistically evaluate required operator action in a potential high radiation field, to compensate for failed safety-related automatic valve actuators.	28	A 1.1 A 4.1 A 4.2 C 3.1 D 5.2 F 3.1	III.C.3.a V.B.3 V.B.4 ORP 25, 63 - 75
2.3.2 System Engineering Program Not Effectively Implemented			**Engineering Support**
a. Program expectations for the system engineers greatly exceeded the resources provided. Some system engineers were assigned the primary responsibility for as many as 10 systems, with an additional 10 systems assigned as backup.	28 29	A 1.1 C 2.1 C 3.1 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5	V.B.3.a V.B.3.c ORP 63, 64
b. Most system engineers could not remember what backup systems they were assigned, and were not knowledgeable in their backup system assignment.	29	C 2.1 C 3.1 D 4.1 D 4.2 D 4.3 D 5.2 D 5.3 D 5.4 D 5.5	V.B.3.a V.B.3.c ORP 63, 64
c. Staffing allocation was roughly based upon other two-unit facilities, however, the three-train safety system design resulted in an increased work load for the system engineers when compared to otherwise equivalent nuclear facilities with two trains.	29	C 2.1 C 3.1 D 5.2 D 5.3 D 5.4 D 5.5	V.B.3.c
d. System engineers generally did not complete their monthly walkdowns or did not sufficiently document them when performed. Some system engineers performed walkdowns of multiple systems in both units on the same day, indicating a cursory review at best.	29	C 2.1 C 3.1 D 5.2 D 5.3 D 5.4 D 5.5	V.B.3.a ORP 63, 64
e. System health reports lacked useful detail and trending information. Most system engineers received no feedback on the content of the system health reports from their supervisors, did not review and track service requests on their assigned systems, did not know how many service requests were outstanding on their systems, did not know how many modifications affected their systems, and did not track and trend problems or particular attributes of their systems.	29	B 1.1 B 2.1 B 3.1 C 2.1 C 3.1 D 3.2 D 3.3 D 3.4 D 3.6 D 3.7 F 4.2	V.B.3 ORP 63 - 72
f. The licensee indicated that trending will not be performed until the end of 1993 when the software becomes available.	29	D 3.2 D 3.3 D 3.4 D 3.6 D 3.7 F 4.2	V.B.3.d(3) ORP 71, 72
g. Several engineers were deficient in training or equivalent work experience, which with the demands on time available for daily responsibilities and a perception of limited resources, resulted in system engineers receiving little training for specific jobs, components, or systems.	29	C 2.1 C 3.1 D 4.1 D 4.2 D 4.3 D 5.2 D 5.4	V.B.3 ORP 63 - 72

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
h. Those [system] engineers who were "hands-on" oriented and focused more on the equipment aspects of their systems tended not to be as involved in technical monitoring and analysis which included design basis issues, system tracking and trending, and proactive activities.	29	C 2.1 C 3.1 D 4.2 D 4.3 F 4.2	V.B.3.a ORP 63, 64
i. Management did not oversee and direct the [system engineer] program in a consistent manner. System engineers reported to different supervisors who had differing standards for implementing the system engineering program.	29	A 1.1 C 2.1 C 3.1 D 5.5	V.B.3.a ORP 63, 64
k. Because of the reactive nature of system engineering work, and networking between operations and maintenance, first line supervisors maintained minimal control over work assigned to the system engineers, who spent over 40 percent of their time supporting emergent work of other site organizations. Thus, the system engineer received support requests that had not been screened for validity by PED supervision.	29	A 1.1 A 2.1 B 1.1 C 2.1 C 3.1 C 4.1 D 5.2 D 5.4 D 5.5	V.B.3.a ORP 63
2.3.3 Engineering Work Backlogs Were Large, Poorly Tracked, and Not Well Managed			**Engineering Support**
a. The licensee did not have an effective method to determine the size and composition of the engineering backlog. This conclusion is based on the fact that the data initially given to the team was grossly inaccurate and it subsequently took more than four weeks to provide reasonably accurate data. The backlog consisted of approximately 10,800 work items on May 1, 1993. ... The backlog did not include work assignments of administrative or contractor personnel.	30	A 1.1 A 2.1 B 1.1 C 2.1 C 3.1 F 7.1	III.C V.B.3 V.B.4 ORP 22 - 28, 63 - 75
b. The number of work items in the backlog was increasing at a net rate of 428 each calendar quarter (seven person-years each quarter). To compensate for this workload, numerous individuals worked more than 70 percent overtime and some worked more than 100 percent overtime in a pay period.	30	A 1.1 A 2.1 B 1.1 C 2.1 C 3.1 D 5.2 D 5.3 D 5.4 F 7.1	III.C V.B.3 V.B.4 ORP 22 - 28, 63 - 75
c. The licensee was not incorporating amendments into site vendor drawings in a timely manner. On March 19, 1993, approximately 11,500 vendor drawings (approximately 50 percent being safety-related) had one or more unincorporated amendments. Drawings with many unincorporated amendments rendered the associated vendor drawings cumbersome to use and impeded work planning and execution. Previous initiatives to reduce this backlog were not effective.	30	D 5.2 D 5.4 D 5.5 E 4.2 F 7.1	III.C.2 III.C.3.c ORP 27
2.3.4 Use of Industry and Site Operational Experience was Inadequate			**Engineering Support**
a. Industry and site OERs performed by the licensee were not comprehensive or timely, and failed to completely address problems or recommendations. In several instances, engineering failed to review and benefit from industry experience, such as described in NRC information notices and bulletins, vendor service bulletins, and industry reports, or site operational experience, which led to avoidable site events, repetitive equipment failures, and additional engineering time expenditures.	30	D 4.2 D 4.3 D 5.4 D 5.5 E 4.1 F 7.1	III.C.3.b V.B.3 V.B.4 ORP 26, 63 - 75
b. The following are examples in which the licensee failed to properly implement the OER program: NRC Information Notice 91-046, "Degradation of Emergency Diesel Generator Fuel Oil Delivery Systems," listed instances where inadvertent painting of fuel injector assemblies, including metering rods, rendered emergency diesel generators inoperable. The licensee's response to the notice indicated that adequate controls were in place and that no further actions were necessary. However, during painting activities, paint dripped into the holes which contained the fuel metering rods, rendering a diesel inoperable as later discovered during the performance of a surveillance test.	30 31	C 2.1 C 3.1 D 4.2 D 4.3 D 5.4 D 5.5 E 4.1	III.C.E.b V.B.3 V.B.4 ORP 26, 63 - 75

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
c. The following are examples in which the licensee failed to properly implement the OER program: During tests in March 1993, the licensee discovered that 36 control rods in Unit 1 were thermally locked. The event occurred following a reactor cooldown in February 1993, with the control rods energized on the core bottom. The licensee could have avoided the event by following the guidance in Westinghouse Technical Bulletin TB-92-05 of May 21, 1992. The licensee received the bulletin in June 1992 but failed to route it to Reactor Engineering and Operations Support Groups. Therefore, its contents were not incorporated into operating procedures by cognizant operational groups.	31	D 2.1 D 4.2 D 4.3 D 5.1 D 5.5 E 4.1 E 4.2	III.C.3.b V.B.3 V.B.4 ORP 26, 63 - 75
d. The following are examples in which the licensee failed to properly implement the OER program: When replacing SDG rocker arms with a modified design, the licensee failed to include specific Cooper-Bessemer service bulletin requirements for torquing and installing modified parts. This could have prevented the replaced rocker arms from functioning properly.	31	D 4.2 D 4.3 D 5.5 E 4.1 E 4.2	III.C.3.b V.B.3 V.B.4 ORP 26, 63 - 75
e. The following are examples in which the licensee failed to properly implement the OER program: During an uncoupled run of a reactor coolant pump, the lower motor bearing failed from a lack of lube oil (LO) after a maintenance worker drained approximately 3 gallons of LO in an attempt to correct a suspect high LO level. An investigation showed that the reactor coolant pump motor bearing oil levels had a history of erratic readings and that a lower reactor coolant pump bearing was damaged during a previous outage because of insufficient LO in the lower bearing.	31	C 2.1 C 3.1 D 4.2 D 4.3 E 1.1 E 1.2 E 1.3 E 1.4 E 4.1	Not Applicable
f. The following are examples in which the licensee failed to properly implement the OER program: In May 1990, the licensee detected high vibration readings on the Unit 1 turbine generator seal oil backup pump, but did not monitor the pump until completing the 1992 outage and inspection of the main turbine and auxiliaries. During turbine startup, high vibration readings were again observed on the seal oil motor and pump bearings that necessitated repair.	31	C 2.1 C 3.1 F 4.1	V.B.3 V.B.4 ORP 63 - 75
g. The licensee assigned limited personnel and hardware resources to the VETIP to receive, distribute, and track vendor information. The licensee added staff temporarily to correct problems, but did not take long term corrective actions, thus permitting the problem to recur. ... Many examples of inadequate incorporation of vendor information were repeatedly noted by QA, ISEG, and other audit groups without substantive corrective action being taken.	31	A 1.1 E 4.2 F 7.1	III.C.2 III.C.3.c ORP 24, 27
h. The licensee had not updated the PRA database to reflect actual plant equipment failure data. ... The licensee was not using the unique capabilities of the PRA group to identify plant equipment reliability or to help in ranking modification or maintenance work. During this evaluation, the licensee used PRA to address team concerns with the reliability of the SDGs, in particular for SDG 22, but only in response to specific and repeated team requests.	31 32	C 2.1 C 3.1 F 3.1	Not Applicable
2.3.5 Insufficient Support to Engineering			**Engineering Support**
a. Management assigned inadequate information systems to aid engineering in evaluating system performance, trending maintenance history, accessing industry and site experience, performing investigations and root cause analyses, and making informed decisions.	32	C 2.1 C 3.1 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2 F 3.1 F 4.1	V.B.3.d V.C.5 ORP 71, 72, 84

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
b. The equipment maintenance history database was not accurate and current because of the poor quality of information loaded into the system, and because of the large backlog of outstanding entries, estimated by the licensee to be approximately 6-8 months.	32	C 2.1 C 3.1 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 F 4.1 F 7.1	III.C.3.c V.B.3.d V.C.5 ORP 27, 71, 72, 84
c. A sample of various databases showed conflicting and incomplete information concerning the maintenance history of CH chillers, failure histories for the SDGs, lists of TMs, and MOV issues.	32	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 F 4.1 F 7.1	III.C.3.c V.B.3.d V.C.5 ORP 27, 71, 72, 84
d. The licensee could not retrieve design basis variances concerning MOV setpoints, and could not track or index Plant Change Forms by system or type.	32	C 2.1 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2 D 8.1 F 7.1	V.B.3.d V.C.5 ORP 71, 72, 84
e. The licensee had to manually search service requests to determine where modified SDG rocker arms were installed, and whether they were installed in accordance with a Cooper-Bessmer bulletin.	32	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 E 4.2	III.C.3.c V.B.3.d V.C.5 ORP 27, 71, 72, 84
f. The effectiveness of engineering was hampered by sparse computer resources and analytical tools to monitor and assess component and or system performance. Until the end of 1992, only five percent of the system engineers had a computer to aid in performing their job function.	32	C 2.1 C 3.1 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2 F 4.1	V.B.3.d V.C.5 ORP 71, 72, 84
g. Backlogged engineering work continued to increase at the rate of seven person-years each quarter, even though most groups in PED and DED worked substantial amounts of overtime.	32	A 1.1 D 5.3 D 5.4 D 5.5 F 7.1	III.C V.B.3 V.B.4 ORP 22 - 28, 63 - 75
h. Management support for training was weak and inequitable. PED was weaker than DED in terms of background and experience, had more staff (179 vs. 148), but were assigned only one-seventh the training budget of DED.	32	A 4.1 C 1.1 C 3.1 D 4.1 D 4.2 D 4.3 D 5.5	V.B.3.b V.B.3.c ORP 65 - 70
i. The licensee fell behind its schedule in completing many [engineering] improvement programs and cancelled some after investing substantial resources. Some corrective actions resulting from improvement programs produced no improvement in performance and were later cancelled. The licensee appeared to classify improvement program action items as "closed" without evaluating their effectiveness.	33	A 1.1 A 4.1 A 4.2 C 1.1 D 5.5	V.B.3 V.B.4 ORP 63 - 75
j. Substantial recurrent problems noted by maintenance, operations, engineering or other groups often resulted in design modifications to resolve the problem. However, the modifications were not installed in a timely manner.	33	A 4.1 B 1.1 C 4.1 D 5.4 F 3.1	III.C.3 V.B.4 ORP 22 - 28, 73, 75
k. The licensee failed to make effective use of studies critical of engineering activities.	33	C 2.1 C 3.1 D 5.5 E 3.1	Not Applicable

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
2.3.6 Configuration Control Weaknesses			**Engineering Support**
a. Configuration control weaknesses which adversely affected safety-related plant equipment, were noted in several instances, such as molded case circuit breakers, SDGs, and environmental qualification of MOVs. In other instances, such as vendor drawings, the team observed weaknesses in configuration control that, if left uncorrected, could adversely affect plant operations. Ineffective management oversight and direction, including insufficient resources, were significant contributors to these weaknesses.	33	A 1.1 A 2.1 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2 D 5.5	Not Applicable
b. The Electrical Setpoint Index for molded case circuit breakers was not properly understood or implemented in the field. ... Although the index contained appropriate criteria, the licensee had not prepared detailed work or procedural instructions for craft personnel to use in interpreting or scaling the index guidance.	33 34	D 1.1 D 2.1 D 4.2 D 4.3 D 5.5 F 6.1	III.D.3 V.B.3 V.B.4 ORP 63 - 75
c. While performing maintenance on molded case circuit breakers, the licensee discovered that the magnetic trip settings were adjusted using the electrical penetration test point calculations for permissible currents rather than trip values obtained from the index. The licensee later determined that the instantaneous trip (magnetic) settings were improperly adjusted for approximately 30 breakers in Units 1 and 2. The licensee found operability concerns with 10 breakers powering MOVs such as containment and accumulator isolation valves.	34	E 1.1 E 1.2 E 1.3 E 1.4 F 5.2	III.D.3 V.B.3 V.B.4 ORP 63 - 75
d. When installing SDG rocker arms with a modified design, the licensee failed to include specific Cooper-Bessmer service bulletin requirements for torquing and installing the modified part, which could have cause the replaced rocker arms to function improperly.	34	D 2.1 E 1.1 E 1.2 E 1.3 E 1.4 E 4.1 E 4.2	III.C.3.b V.B.3 V.B.4 ORP 26, 63 - 75
e. Once alerted to the bulletin requirements, installation of the rocker arms was still not completed correctly, i.e., the requirement to replace both the intake and exhaust rocker arms as a set was not accomplished.	34	E 1.1 E 1.2 E 1.3 E 1.4 E 4.1 E 4.2 F 5.2 F 6.1	V.B.3 V.B.4 ORP 63 - 75
f. The licensee also had to resort to hand searches of service requests to locate where the modified rocker arms were installed.	34	C 3.1 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 F 7.1	V.B.3.d V.C.5 ORP 71 - 72, 84
g. The licensee did not maintain the environmental qualification of valve actuator motors in containment by installing "T" drains as required by design. The licensee found five actuator motors that did not have "T" drains. The engineering staff evaluated three of the five, concluded that no action was required, and was evaluating corrective actions for the remaining two valve actuator motors.	34	C 2.1 C 3.1 D 3.3 D 5.2 D 5.4 F 6.1	Not Applicable
h. The many unincorporated amendments to vendor drawings remained significant and could impede work planning and execution.	34	D 5.2 D 5.4 E 4.2 F 7.1	III.C.3.c ORP 27
2.3.7 Functional and Programmatic Weaknesses Could Adversely Affect the Operability of the Essential Chilled Water System			**Engineering Support**
a. The licensee did not complete an analysis for the CH system under low heat load conditions. If an accident occurred during cold weather and all chillers operated, the chillers would be under loaded, causing surging and failure, resulting in loss of CH cooling of safety related equipment. ... The licensee made a commitment to the team to evaluate under-loading of chillers during accident conditions.	35	F 3.1	III.D.2 ORP 30, 31

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
b. Preoperational, surveillance, and post-maintenance testing performed on the CH system did not demonstrate that the system would be operable for extended periods of time under design basis heat load conditions. The piping design configuration did not allow the CH system to be tested with heat loads representative of those anticipated during accident conditions.	35	See ORP	III.D.2 ORP 30, 31
c. Compressor refrigerant and oil contamination was a long term problem that significantly affected reliability. The vendor proposed installing a proven refrigerant clean-up kit that would allow uninterrupted chiller operation. Although the modification was approved in September 1991 for installation in 1992, its installation date was deferred to October 1994 for Unit 1 and April 1995 for Unit 2.	35	A 4.1 C 1.1 C 4.1 F 3.1	III.D.2 ORP 30, 31
d. In 1993, after further evaluation and repeated attempts at installation, the licensee cancelled plans to install proximity vibration probe assembly recommended by the vendor in 1988 to detect high speed thrust bearing displacement and an automatic compressor trip function for the 300-ton compressors to prevent catastrophic failure.	35	A 1.1 C 1.1 C 4.1	III.D.2 ORP 30, 31
e. In 1989, the licensee implemented a temporary modification to remove an ECW valve actuator which automatically controlled flow to the chiller condensers by using an upstream manual valve rather than correcting automatic control system design and material deficiencies.	35	A 4.1 F 3.1	III.D.2 ORP 30, 31
f. After maintenance work was performed on the feeder breaker for essential chiller 21C, the chiller was declared operable without PMT. The following day the chiller tripped during a routine start attempt because of breaker problems.	36	E 1.1 E 1.2 E 1.3 E 1.4 F 6.1	V.C.7 ORP 87
g. The maintenance craft personnel introduced air into the essential chillers and flooded a control panel with oil because they did not understand how the chillers function under vacuum. Inadequate training caused poor maintenance work and contributed to degraded performance of the equipment and lack of availability.	36	D 4.1 D 4.2 D 4.3 D 5.5 F 5.2	V.B.2.e ORP 60
2.3.8 Untimely Resolution of Fire Protection Issues -			Engineering Support
a. Excessive shrinkage and resultant cracks of Hydrosil-type penetration seals allowed free air to pass between fire areas and raised questions of structural integrity, making the seals ineffective fire barriers. The problem was previously identified in 1990 and was thought to have been corrected after a 100 percent survey in 1991-92 and subsequent repairs/rework. The cracking was again identified in March 1993. The investigation of the problem was scheduled to be completed by May 31, 1993.	36	D 1.1 F 3.1	Not Applicable
b. The Pyrotronics fire protection computer system, which monitors fires in various plant areas and alarms in the control room, was unreliable with numerous chronic problems, including defective detectors and electronic transmitter boards. Numerous false alarms frequently annunciated (20-30 each day) and control room operators could not quickly ascertain which detector was in alarm status.	36	A 4.1 C 4.1 F 3.1	V.B.1.b(3) ORP 53, 54
c. Replacement parts were not available [for the Pyrotronics] because the system was obsolete. Although a modification was proposed to replace the system, the modification received low priority, and was not scheduled for installation until 1996. The team raised concerns about the system reliability and the ability of operators to determine if and where a fire existed.	36	A 4.1 C 4.1 F 3.1	V.B.1.b(3) ORP 53, 54
d. At the time of the evaluation, the licensee had a large backlog of 361 open SRs for the fire protection systems. ... The large backlog indicated that the reliability of the fire protection system was questionable.	36	A 4.1 C 4.1 F 1.1	V.B.1.b(3) V.B.2.g ORP 53, 54, 62

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
e. In April 1993, the licensee located significant quantities of transient combustibles such as wooden tables, waste oil, oil soaked rags, and miscellaneous combustible items located throughout the plant. The presence of such large amounts of transient combustibles was indicative of an inadequate control program.	37 37	D 4.2 ~~D 4.3~~ E 2.1 E 5.2	Not Applicable
2.4.1 Ineffective Direction and Oversight		**Management and Organization**	
a. Senior management failed to provide the staff clear direction and oversight in several key areas including performance standards and station priorities. Frequent, conflicting messages about implementation of these standards and priorities were sent by senior management.	38	A 1.1 A 2.1 B 1.1 D 5.1 D 5.5	V.A.2 V.A.3 ORP 44 - 50
b. Numerous uncontrolled memoranda and oral instructions were used to change standards and priorities. ... Management's stated emphasis on "doing things right, not just doing them" often seemed to conflict with these memoranda and instructions. As a result, the staff questioned the credibility of senior management.	38	A 1.1 B 1.1 B 2.1 B 3.1 D 2.1 D 5.1 D 5.5 D 6.2	Not Applicable
c. Middle managers often failed to obtain feedback on problems and give consistent direction because they did not interact frequently enough with people in the plant.	38	A 2.1 B 1.1 B 2.1 B 3.1 C 3.1 D 5.1 D 5.5	Not Applicable
d. Although the licensee initiated the management surveillance program in 1990 in an attempt to increase management's presence in the plant, the plant staff did not fully accept this program. The perception by plant personnel was that the managers focused on minor housekeeping items rather than effectively interfacing with personnel and providing one-on-one direction and feedback.	38	A 1.1 A 2.1 B 2.1 B 3.1 D 5.1 D 5.5 F 2.1	Not Applicable
e. The lack of clear and consistent station management direction combined with senior management's over-involvement in lower level issues created a widespread perception that middle managers had little authority.	38	A 1.1 A 5.1 A 5.2 A 5.3 A 5.4 B 1.1 B 2.1 D 5.1 D 5.5	V.A.2 V.A.3 ORP 44 - 50
f. Over-involvement contributed to a high senior management workload, limited their time available to focus and provide direction on higher level issues, and discouraged ownership and accountability at the lower levels of management.	39	A 1.1 A 2.1 B 1.1 B 2.1 D 5.1 D 5.4 D 5.5	V.A.2 V.A.3 ORP 44 - 50
g. Many of the plant's more important activities and initiatives, such as root cause analyses, didn't receive consistent and clear management direction and didn't have an owner that really felt accountable.	39	A 1.1 A 2.1 C 1.1 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4	V.A.2 V.A.3 ORP 44 - 50
h. Key performance issues were often not fully appreciated by senior management even after they were identified by outside industry and regulatory agencies, despite precursors and warnings within the organization at STP.	39	A 1.1 B 1.1 B 2.1 D 5.5	V.A.2 V.A.3 ORP 44 - 50
i. Most managers at STP lacked commercial nuclear experience outside of STP. Some managers had Navy nuclear experience, but had very limited experience at STP.	39	A 2.1 D 4.2 D 4.3 D 5.5	Not Applicable
j. Many managers had recently been rotated into positions for which they had little background. The majority of the department level managers had been rotated one or more times during the past year.	39	A 2.1 D 4.2 D 4.3 D 5.5	Not Applicable

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN		ORP
2.4.2 Poor Support and Resource Utilization		**Management and Organization**		
a. Management failed to provide and adequately focus sufficient resources to maintain performance levels and standards for the existing plant conditions. Significant station activities were not adequately funded despite the clearly stated objections of the responsible middle level managers.	39	A 1.1 A 4.2 C 1.1 D 5.3 D 5.5	A 4.1 A 5.2 D 5.2 D 5.4	V.A.2 V.A.3 ORP 44 - 48, 50
b. Middle level managers perceived that resources would not be approved if the proposed line item caused the department budgets to exceed the target budget levels established by senior management.	39	A 1.1 A 4.2 C 1.1 D 5.5	A 4.1 A 5.2 D 5.2	V.A.2 V.A.3 ORP 44 - 48, 50
c. STP management had not established management systems that would effectively and efficiently accomplish the strategic goals listed in the MOP by implementing these goals into the daily work schedule.	39	A 1.1 B 2.1 C 1.2 D 5.5	A 5.2 C 1.1 D 5.4	V.A.2 V.A.3 ORP 44 - 48, 50
d. The planning, scheduling, and work process controls did not support the timely and reliable completion of work by maintenance, operations, and engineering. Although station management had recognized this problem, they had failed, until recently, to focus the necessary resources to correct this situation.	39	A 4.1 C 1.1 C 4.1 D 5.2 F 1.1	A 5.2 C 1.2 D 1.1 D 5.3	III.B.1 V.B.1.b (1) V.B.2.b ORP 14
e. Senior management's reaction to unforeseen, emergent work was to defer or cancel other previously budgeted line items to maintain the target budget expenditure goals. ... STP routinely experienced a significant end-of-year deficit in the accomplishment of planned, priority work because of the failure to adequately anticipate and budget for emergent work.	40	A 4.1 C 1.1 D 5.3	A 5.2 C 1.2 D 5.5	V.A.3 ORP 50
f. Staffing levels were marginal or insufficient in several key areas.	40	A 4.1 C 2.1 C 5.1 D 5.2	C 1.1 C 3.1 C 5.2	V.A.3 V.B.1.a V.B.3.c ORP 50 - 52
g. Recommended staffing levels in the most recent [outside contractor] study were based on incorrect assumptions on productivity.	41	C 1.1 C 3.1 C 5.2	C 2.1 C 5.1	V.B.1.a V.B.3.c ORP 51, 52
h. Staff productivity was not effectively measured or understood by management. Although the licensee identified inefficient work control processes as major contributors to the large work backlog, the MIS did not provide adequate measures of staff productivity. The maintenance required to complete SRs was not accurately measured and no system existed to measure engineering staff productivity. Additionally, the licensee did not account for all overtime worked by salaried employees.	41	A 1.1 D 3.1 D 3.3 D 3.5 D 3.7 D 3.9	D 1.1 D 3.2 D 3.4 D 3.6 D 3.8 F 1.1	Not Applicable
i. In addition to staffing based upon incorrect assumptions on productivity, the licensee generally appeared to be staffing based upon levels predicated on the station operating in a stable condition with only long term requirements and no significant backlogs or emergent workloads.	41	A 4.1 C 2.1 C 5.1 D 5.2 D 5.4	C 1.1 C 4.1 C 5.2 D 5.3	Not Applicable
j. Support of training, including funding, was weak.	41	A 4.1 D 4.1 D 4.3	C 1.1 D 4.2 D 5.2	V.A.3 ORP 50
k. The scope and duration of operations training was frequently altered to support manpower shortages in the plant.	42	A 4.1 C 5.2 D 4.2 D 5.2	C 5.1 D 4.1 D 4.3	V.B.1.a ORP 52

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
l. Management did not adequately budget for or effectively manage spare/replacement parts.	42	A 4.1 A 4.2 C 1.1 D 5.2	V.C.8 ORP 88 - 89
m. Several problems identified by the team indicated that this system [master parts list] may have been based on an inaccurate economic model, coupled with errors in the plant labeling system.	42	See ORP	V.C.2 ORP 79, 80, 88, 89
n. It appeared that management considered the entire inventory as homogenous when assessing inventory turnover frequency rather than separating long-term strategic from rotating stock. When requested by the team to provide numbers identifying the turnover frequency of routinely used parts, it was apparent that these figures were not considered or monitored by STP.	42	A 4.2	V.C.8 ORP 88, 89
o. Station improvements were adversely impacted due to budget pressures. Examples: Plant Labeling Program; Engineering Improvement Program.	42	A 4.2 C 1.1 D 5.2 D 5.5	V.A.3 ORP 50, 79, 80
2.4.3 Communications and Teamwork Were Weak		**Management and Organization**	
a. Expectations regarding competing priorities between budget, schedule, and safety performance were not communicated well.	42	A 1.1 A 4.1 A 4.2 B 1.1 C 1.1 C 1.2 C 4.1 D 5.2 D 5.4 D 5.5	V.A.2 ORP 44 - 48
b. Vertical communications were particularly weak. Senior managers did not foster frank, open feedback from lower managers and staff.	42	A 1.1 B 1.1 B 2.1 D 5.1 D 5.2 D 5.3 D 5.5	V.A.2 V.A.3 ORP 45, 47, 48
c. Horizontal communications and interface problems added to the difficulty of completing work using established processes. There was a lack of coordination and accountability between disciplines during routine work. As a result, an excessive number of task forces, outside the normal organization, seemed to be required to accomplish work.	42	A 1.1 B 1.1 D 1.1 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5 F 5.2 F 6.1	V.A.2 ORP 47, 48
d. The level of routine administrative workload and the reactive mode of the organization tended to leave little time for communications and coordination within work groups and with other groups. This problem existed, to some extent, at all levels of the organization.	43	A 1.1 A 4.1 A 4.2 B 1.1 C 4.1 D 5.4	V.A.2
e. The team observed during meetings to discuss the Unit 1 workload and startup schedule that senior management did not appreciate the impact of their startup schedule expectation on the operations department workload and had not accurately weighed the competing priorities of safety and schedule adherence partly due to a lack of operation's input into the startup schedule.	43	A 2.1 C 1.1 C 4.1 D 5.2 D 5.3 D 5.4 D 5.5	V.B.1.a ORP 52
f. Management had failed, in some cases, to clearly define and communicate appropriate standards and priorities for personnel and plant performance. In addition, there were often conflicting messages sent in the implementation of these standards.	43	A 1.1 B 1.1 D 5.5	V.A.2
g. The threshold of SPR initiation and depth of root cause analyses were not well defined, and communicated to the staff. As a result, the quality of root cause analyses was often weak, but varied significantly between groups and individuals within a group.	43	A 1.1 B 1.1 E 1.1 E 1.2 E 1.3 E 1.4 E 2.1	V.C.1 ORP 78
h. The MOP goal of increased reliability was in conflict with the deferral of maintenance.	43	A 1.1 C 1.1 C 1.2 C 4.1 D 5.5 F 1.1	Not Applicable

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
i. The team attended meetings where senior management dominated the meeting to such an extent that there was little communication except top down. On several occasions after senior management left the meeting, the team observed markedly improved communications and coordination.	43	A 2.1 B 1.1 B 2.1 B 3.1 B 4.1 D 5.1 D 5.3 D 5.4 D 5.5	V.A.2
j. Although both programs [Speakout and Employee Assistance] were supposed to be anonymous, there was a perception among many employees that these programs were not, which limited their effectiveness.	43	B 2.1 B 3.1 E 2.1	V.C.10 ORP 90
k. There was also a perception that management was not interested in hearing about problems as demonstrated by the lack of results when issues were brought forward.	44	A 1.1 B 1.1 B 2.1 D 5.1 D 5.3 D 5.5	V.A.2 V.A.3
2.4.4 Ineffective Corrective Action Process		**Management and Organization**	
a. Poor problem identification, shallow root cause analyses, inadequate safety impact evaluations, and lack of aggressive problem resolution, combined with poor information systems and budgetary constraints, resulted in short term rather than long term solutions to station problems.	44	A 4.1 A 4.2 C 1.1 C 1.2 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 E 1.1 E 1.2 E 1.3 E 1.4	V.A.3 V.C.1 V.C.5 ORP 50, 78, 84
b. The team found several examples where confusion and lack of training resulted in SPRs not being issued in a timely manner on safety-related equipment. The licensee's QA department had repeatedly notified management of a weakness in the definition of "conditions adverse to quality" which resulted in licensee personnel not being aware of when to write a SPR.	44	D 4.2 D 4.3 D 5.4 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4 E 2.1	V.C.1 ORP 78
c. Additionally, lack of effectiveness in reporting problems reflected workers' willingness to live with problems, due at least in part to conflicting management expectations and standards regarding material condition.	44	A 1.1 A 4.1 A 4.2 B 1.1 D 5.1 D 5.2 D 5.3 D 5.5 E 2.1 F 5.2	V.C.1 ORP 78
d. Several individuals outside of the CAG who performed root cause analyses had not been adequately trained. Also, in the case of engineering, individuals performing root cause analyses often were not knowledgeable on the system or component of concern.	45	D 4.2 D 4.3 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4 F 3.1	V.B.3.b V.C.1 ORP 65 - 75, 78
e. Additionally, until very recently, the licensee had not identified fatigue as a root cause of personnel errors.	45	D 5.1 D 5.3 D 5.4 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4	V.C.1 ORP 78
f. The team identified several instances where inadequate safety evaluations resulted in ineffective corrective actions.	45	C 2.1 C 3.1 D 4.2 D 4.3 D 5.5	V.C.1 ORP 78
g. The team identified several examples where timely and effective corrective actions were not taken.	45	D 5.5 E 1.1 E 1.2 E 1.3 E 1.4	V.C.1 ORP 78
h. Although senior management expressed the desire to become more responsive on corrective actions, it appeared from documentation and interviews that little progress had been made and that budgetary pressures had an adverse impact on corrective actions.	45	A 1.1 A 4.1 A 4.2 C 1.1 C 1.2 C 4.1 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4	V.A.3 ORP 50

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
i. The CAG had been budgeted to perform .... However, the current workload was more than twice this amount as well as additional scope.(paraphrased)	45	A 4.1 C 1.1 C 1.2 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4	V.C.1 ORP 78
j. The team found that the CAG had been funded by reducing or eliminating the corrective action funds of other departments. In fact, the corrective action workload had increased in maintenance, operations, and engineering since the establishment of the CAG. The limited staffing available for SPR review and root cause analysis had contributed to shallow and hurried efforts.	45	C 1.1 C 1.2 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4	V.C.1 ORP 78
k. The team found the CAG lacked ownership of the corrective action program with respect to the SPR reviews and root cause analysis not performed by CAG.	46	A 1.1 D 5.5 E 1.1 E 1.2 E 1.3 E 1.4	V.C.1 ORP 78
l. The effectiveness of ISEG in identifying root causes of problems and proper corrective actions was also limited. The scope and detail of work assigned to ISEG had exceeded the capability of the assigned staff to meet those functions required by technical specifications in a timely manner.	46	A 4.1 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5 E 4.1	V.C.1 ORP 78
m. Coordination of the OER program suffered severely from ISEG's overloaded and limited staff.	46	A 4.1 D 5.2 D 5.4 D 5.5 E 4.1	Not Applicable
n. Managements failure to provide more than the technical specification minimum staffing for ISEG and the frequent change or absence of ISEG directors were further evidence of management's lack of support for corrective actions.	46	A 4.1 D 5.1 D 5.2 D 5.3 D 5.4 D 5.5	Not Applicable
2.4.5 Ineffective Utilization of Self-assessment and Quality Oversight Functions		**Management and Organization**	
a. Managers did not respond effectively to the findings, concerns, and recommendations of their principal self-assessment and quality oversight functions, including the NSRB and QA. In addition, management had not fully supported the ISEG review for lessons learned.	46	A 1.1 A 4.1 D 5.1 D 5.3 D 5.4 D 5.5 E 3.1	V.A.2 V.A.3 ORP 44 - 50
2.4.6 Inadequate Information Systems		**Management and Organization**	
a. The computerized information system consisted of several non-integrated hardware configurations, including seven local area networks. There were also several uncontrolled computer programs utilized in the control room for various work control processes. There was no interactive interface between the different computers which meant that similar data was duplicated on different computers. This method of managing data was inefficient and increased the probability of error due to multiple entry at different time intervals. The team found that data in several areas was unreliable.	47	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2	V.B.1.b (4) V.C.5 ORP 55, 84
b. STP was experiencing significant delays in processing data from its main computer system due to hardware and processing limitations.	47 48	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2 D 5.4	V.C.5 ORP 84
c. The team identified and confirmed the following weaknesses in information systems: Equipment history records were incomplete and approximately eight weeks behind in being updated. This resulted in the licensee's tendency not to rely on these records.	48	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2 D 5.4 F 7.1	III.C.3.c V.C.5 ORP 27, 84

NRC DIAGNOSTIC EVALUATION TEAM REPORT OBSERVATION	DER PG.	ACTION PLAN	ORP
d. The team identified and confirmed the following weaknesses in information systems: The acquisition of parts information was cumbersome, slowing down maintenance work package preparation.	48	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2 D 5.4 D 5.5 F 6.1	V.C.5 ORP 84, 88
e. The team identified and confirmed the following weaknesses in information systems: The information system used for outage planning was not capable of performing assessments of critical path items.	48	C 4.1 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2	V.C.5 ORP 84
f. The team identified and confirmed the following weaknesses in information systems: Computer assistance to aid the system engineer in documenting and trending system performance and condition was not generally available. The licensee had purchased approximately 700 personal computers in 1992, however, most of these remained in the warehouse at the time of the evaluation.	48	C 2.1 C 3.1 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2	V.B.3.d ORP 71, 72
g. The team identified and confirmed the following weaknesses in information systems: The PRA database was not updated to reflect actual plant failure data.	48	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2	Not Applicable
h. The team identified and confirmed the following weaknesses in information systems: Information used to derive plant performance indicators was inaccurate and misleading.	48	C 1.1 C 1.2 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9	V.C.5 ORP 84
i. The team identified and confirmed the following weaknesses in information systems: Information to support management in budget justification was missing or inaccurate.	48	C 1.1 C 1.2 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.4 D 5.5	V.C.5 ORP 84
j. The team identified and confirmed the following weaknesses in information systems: Staff productivity measurements were nonexistent or misleading.	48	A 1.1 C 1.1 C 1.2 D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.2 D 5.5	V.C.5 ORP 84
k. The licensee was in the process of purchasing a new computer program directed at improving information systems. However, managements errors in establishing the current system were being repeated in the information improvement program in that input and feedback from end users was not being adequately incorporated.	48	D 3.1 D 3.2 D 3.3 D 3.4 D 3.5 D 3.6 D 3.7 D 3.8 D 3.9 D 5.3	V.C.5 ORP 84
l. Management's lack of support for information systems improvement was further evidenced by the failure to replace, in a timely manner, the manager responsible for the improvement program following his promotion to another on-site organization.	48	A 1.1 A 2.1 D 5.4 D 5.5	Not Applicable

FOCUS AREA INITIATIVES ACTION PLANS
Index

Focus Area	Action Plan	
Leadership and Management	A1.1	Establish and communicate goals.
	A2.1	Technical supervisory/people skill requirements.
	A3.1	Develop processes that are used to implement changes on site.
	A4.1	Balance between short-term costs and long-term investment.
	A4.2	Demonstrate a commitment to long-term improvement by investment in programs that have long-term benefits.
	A5.1	Identify inequities between organizations.
	A5.2	Employee Incentive Program.
	A5.3	Facilities and Work Areas equity.
	A5.4	Corporate and station policy application.
Communication and Teamwork	B1.1	Foster a culture and develop processes, promote station standards for communication and teamwork.
	B2.1	Increase individual involvement, improve personnel and customer involvement.
	B3.1	Develop the most effective communication tools for conducting business.
	B4.1	Implement a continuous improvement process.
Resources	C1.1	Planning/Budgeting guidelines.
	C1.2	Integrated management systems.
	C2.1	Clearly define responsibilities/site expectations for System Engineers.
	C3.1	Improve System Engineering organization performance.
	C4.1	Establish priority system(s) and scheduling support plan.
	C5.1	Short-term (prior to each unit start-up) Operator staffing.
	C5.2	Short-term and long-term operator staffing.
	C6.1	Cost-benefit analysis for a second control room simulator.
Human Performance	D1.1	Analyzing, improving, and maintaining effective work processes.
	D2.1	Administration, control, standards, etc. for STP procedures.
	D3.1	Establish a site Management Information Systems Users Group.
	D3.2	Long Range Information Systems Plan.
	D3.3	Local area network centralized databases.
	D3.4	Short-term Plan for automation and communication.
	D3.5	Long-term Plan for automation and communication.
	D3.6	Improve Information Systems business processes.
	D3.7	Information Systems end user training.
	D3.8	Ensure Station software is developed and maintained.
	D3.9	Data/Validation Control procedure for Databases.
	D4.1	Improve coordination between Plant and Training department.
	D4.2	Establish personnel training as a Station priority.
	D4.3	Develop and implement a long-range training vision and plan.
	D5.1	Improve environment promoting individual respect and teamwork.
	D5.2	Assess station philosophy regarding resources.
	D5.3	Improve morale and work ethics to enhance human performance.
	D5.4	Time management standards that promote human performance.
	D5.5	Philosophy promoting empowerment of employees/develop responsibility/ accountability.
	D6.1	Short-term Technical Specifications enhancement.
	D6.2	Long-term Technical Specifications enhancement.

Focus Area	Action Plan	
	D7.1	Evaluate existing external commitments.
	D7.2	Improve external commitment management process.
	D8.1	Consolidate and maintain the licensing and design basis of facility.
Self Assessment & Corrective Action	E1.1	Ensure adequate and effective problem identification, etc.
	E1.2	Ensure adequate and effective root cause analysis.
	E1.3	Ensure adequate and effective corrective action selection and implementation.
	E1.4	Ensure adequate and effective trend analysis and oversight.
	E2.1	Educate station personnel/correcting problems.
	E3.1	Culture that promotes continual self-assessment and problem correction.
	E4.1	Enhance site OER program.
	E4.2	Enhance vendor Technical Information program.
Material Condition & Plant Reliability	F1.1	Reduce backlog of material condition deficiencies.
	F2.1	Housekeeping and equipment/structure preservation practices.
	F3.1	Equipment failure/repetitive maintenance root cause analysis program.
	F4.1	Improve Preventive/Predictive Maintenance program.
	F4.2	Enhance reliability centered Maintenance program.
	F5.1	Enhance elements that facilitate quality work performance.
	F5.2	Enhance performance standards/measures/expectations.
	F5.3	Improve interface between Quality Control and Maintenance.
	F6.1	Improve work package planning process.
	F7.1	Backlog of engineering documents and unincorporated amendments.

HL&P
OPERATIONAL READINESS PLAN
Index

HL&P
OPERATIONAL READINESS PLAN
Index

SOUTH TEXAS

I. BASIS FOR CONCERN

South Texas Project (STP) has had a decline in performance during the past two Systematic Assessment of Licensee Performance (SALP) periods. Performance problems stem from three broad areas, which include material condition and housekeeping, human performance, and organizational performance.

Historically, hardware problems, some of which are repetitive, have resulted in numerous plant trips, transients, engineering safety features (ESF) actuations, and forced outages. Most of these system and component problems have been limited to balance-of-plant equipment, but there are longstanding safety-related hardware problems that have not been fully resolved.

There are several underlying causes for the poor material condition and the poor level of housekeeping outside of the radiological controlled area (RCA). These include: the age of the equipment (although Unit 1 and Unit 2 only have been operating since 1988 and 1989, respectively, the construction period was lengthy); lack of preventive maintenance of non-Technical Specification governed equipment; a perceived lack of ownership by the Operations Department; weaknesses with the work control, planning, and scheduling processes; design problems; poor craft workmanship; lack of engineering support; lack of management and supervisory visibility in the plant; and, insufficient resources or ineffective resource allocation in the maintenance area. The licensee has not been able to effectively manage the corrective maintenance backlog. Poor prioritization of corrective maintenance work items has resulted in increased safety system unavailability and unnecessary actuations of ESF components. The level of housekeeping outside of the RCA is poor.

Personnel errors also have resulted in reactor trips, ESF actuations, and Technical Specification violations. The results of the routine inspection program identified several causes for personnel errors that have resulted in plant events. These include: inadequate procedures; inattention to detail; miscommunications; lax attitude of accomplishing work; and inexperienced or poorly trained personnel.

Other problems and concerns pertaining to organizational performance have been noted. Over the past two years, several instances of willful violations were committed by low-level licensee and contractor personnel. Most were in the Maintenance and Nuclear Security Departments. Of the 25 open Department of Labor (DOL) Section 210 (211) complaints that involve Region IV power reactor licensees, 12 pertain to current and former STP employees and contractor personnel. DOL has ruled, or is expected to rule that STP discriminated against four individuals for engaging in protected activities. Management and worker morale appears low in some departments. The Plant Operations and Nuclear Training Managers recently left the facility. They expressed concerns to NRC about the management style of senior licensee management. Several instances of internal and external miscommunications have been noted. During two 1992 events, station

D/4

In December 1992, the licensee began to implement a site-wide climate survey to all station personnel. The results are expected in February 1993.

Several management changes have occurred at STP over the past six months. In May 1992, the Plant Manager, Mr. Mark Wisenburg, was replaced by Mr. Gary Parkey, the former Planning and Assessment Manager. In June 1992, the Vice President of Nuclear Support retired and his responsibilities were assigned to other existing organizations. In July 1992, Mr. Thomas Underwood was assigned to the new position of Deputy Plant Manager. In September and October 1992, the Plant Operations Manager and the Nuclear Training Manager, respectively, were dismissed. These positions were subsequently staffed by other licensee managers. Because these changes are recent, the Region has not fully evaluated their effectiveness.

A regional team inspection was conducted in February 1992, which evaluated STP's program for implementing requirements of Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance." The team identified that many motor-operated valves (MOVs) were overthrusting when operated. In addition, an NRC Vendor Branch Inspection determined that stall thrust and overthrust information supplied by Westinghouse could not be used generically by a licensee without a site-specific evaluation. During an inspection conducted in November 1992, region-based inspectors determined that the licensee has resolved these issues.

In March and April 1992, a special regional team inspection was conducted to gather information to enable NRC to address several allegations and related concerns that were identified in a 10 CFR 2.206 petition. NRC substantiated a number of the petitioners' concerns and allegations but most did not have a direct bearing on safety or regulatory requirements. Two violations were identified involving escorting of site visitors. In addition, issues were identified regarding the effect of an increasing service request backlog. An Office of Investigation (OI) investigation of an alleger's claim of employment discrimination (termination for engaging in protected activities) has been completed, and the report will be issued in the near future.

A special inspection was conducted in May and September 1992, relative to the failure by the licensee to independently test the reactor trip breaker shunt trip coil, entry into Technical Specification (TS) 3.0.3 because of the deficient surveillance test, licensee management's failure to inform licensed operators of this condition, and a second TS 3.0.3 event. Five apparent violations were identified, one of which is potentially willful. An enforcement conference will be conducted following the completion of an OI investigation of these issues.

The most recently completed SALP period was from June 2, 1991, to August 1, 1992. The area of Plant Operations remained a Category 2. A declining trend was identified in the Maintenance/Surveillance functional area, which resulted in a performance rating of Category 2, Declining.

DATA SUMMARY

I. OPERATIONAL PERFORMANCE

A. Scram Summary

None

B. Significant Operator Errors

None

C. Procedures

During the past few months, numerous examples of plant events and problems have been caused by the failure to follow procedures or following inadequate procedures. These procedure problems have caused ESF actuations. loss of equipment availability, and Technical Specification violations.

II. CONTROL ROOM STAFFING

A. Number of Licensed Operators

	SRO	RO	TOTAL
Licensed Operators	47	39	86

B. Number and Length of Shifts

5 shifts: 3 operating (8 hour shifts), 1-training, 1-off

C. Role of STA

One STA is shared between the two units. They are not assigned to a specific shift crew, nor do they receive training with a specific shift crew. STA's do not hold a senior operator's license. The STA's primary duty is to act as an accident prevention and mitigation advisor to the shift supervisor.

D. Requalification Program Evaluation

The requalification program was evaluated as satisfactory during separate evaluations in March 1990 and March 1992. A licensed operator training inspection will be conducted at South Texas during January 1993 in accordance with Temporary Instruction for Licensed Operator Requalification Program Evaluation.

components are not considered new. There have been many plant events and forced outages primarily because of balance-of-plant equipment problems.

B. Other Hardware Issues

Several longstanding problems associated with the essential cooling water system (dealloying and weld cracking), the emergency diesel generators, the main feedwater system, Westinghouse Model DS-206 circuit breakers, and essential chillers.

The maintenance service request (SR) backlog consists of approximately 5400 open SRs. The licensee has been unsuccessful in significantly reducing the backlog of open SRs. In addition, difficulties in work coordination and planning have resulted in decreased safety system availability.

VI. PRA

A. PRA Insights

STP is a newer Westinghouse four loop NSSS with a 3 train ECCS design. The ECCS design is unique in that each train delivers flow to a specific RCS loop with no ECCS injection into RCS loop 4 and no cross ties to the other loops. The success criteria for a large break LOCA requires one train of injection to an intact loop. For a small break LOCA, any one train of ECCS is sufficient regardless of the location of the break.

The RHR pumps are separate from the LPSI pumps and the entire RHR system is inside containment. The HPSI pumps take suction directly from the sump. Therefore, they are not dependent on suction from the LPSI pumps in the recirculation mode.

There are 3 EDGs per unit (one for each ECCS train). The reliability of all six EDGs is above 0.975. However, the unavailability due to maintenance is higher than the industry targets.

B. PRA Profile

The STP PSA was submitted to the NRC in 1989 and included analyses of internal and external events. As a result of the PSA findings, an important modification was implemented. This was the connection of the positive displacement charging pump to the technical support center DG to provide RCP seal cooling in the event of a total loss of AC power.

STP responded to GL 88-20 by submitting a level 2 IPE and IPEEE in August, 1992. The original PSA estimated a core damage frequency

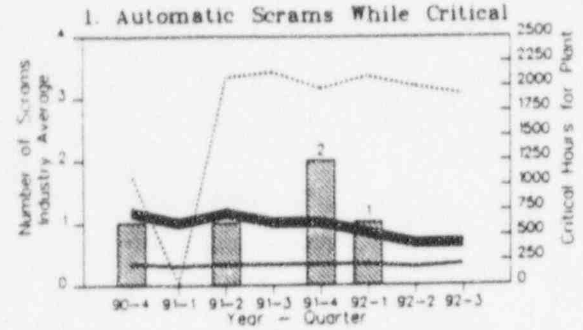
PENDING	The staff is considering escalated enforcement action for apparent violations associated with inadequate licensee control of actions upon entry into Technical Specification 3.0.3.
7/1991	SEVERITY LEVEL III VIOLATION - This case concerned physical security violations including one STP employee bringing a firearm into the protected area. The NRC Staff mitigated the base civil penalty of $50,000 based on licensee identification of the violations and the fact they took prompt corrective action.
12/1991	CIVIL PENALTY - This case involved the licensee's failure to keep complete and accurate records concerning safety-related equipment. ($50,000)
PENDING	The staff is considering escalated enforcement action for a finding by the Department of Labor that the licensee discriminated against an individual during the construction of the plant.

SOUTH TEXAS

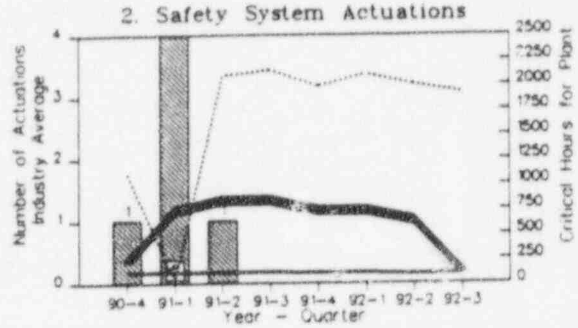
90-4 to 92-3 QUARTERLY DATA

Legend:
- Indicator
- Older Plant 6 Qtr Moving Average
- Critical Hours
- Plant 6 Quarter Moving Average (Long Term Trends)

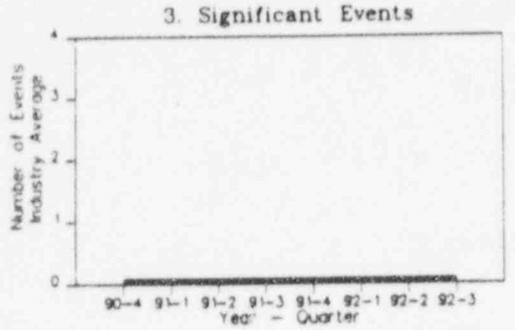
1. Automatic Scrams While Critical



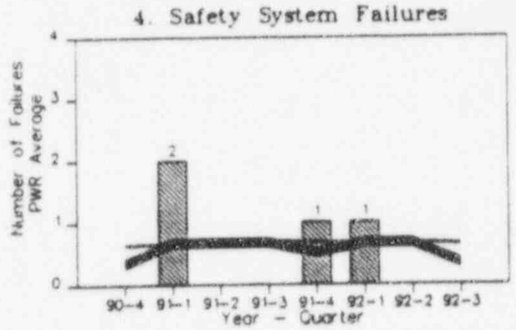
2. Safety System Actuations



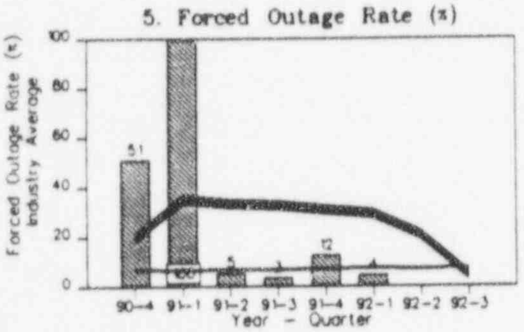
3. Significant Events



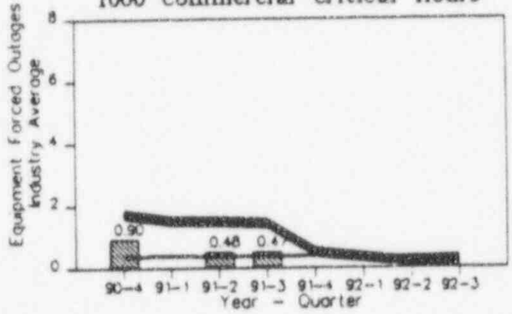
4. Safety System Failures



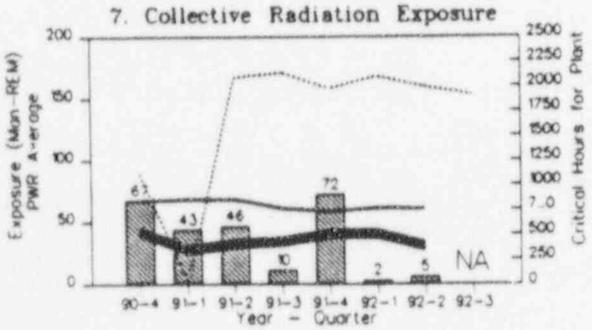
5. Forced Outage Rate (%)



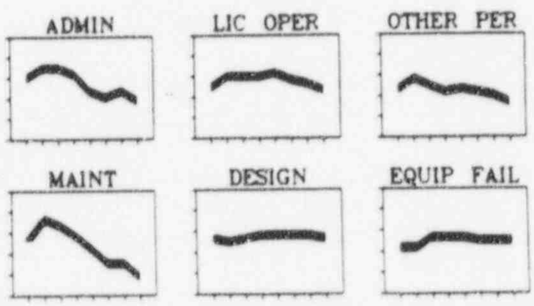
6. Equipment Forced Outages/
1000 Commercial Critical Hours



7. Collective Radiation Exposure



8. Cause Codes

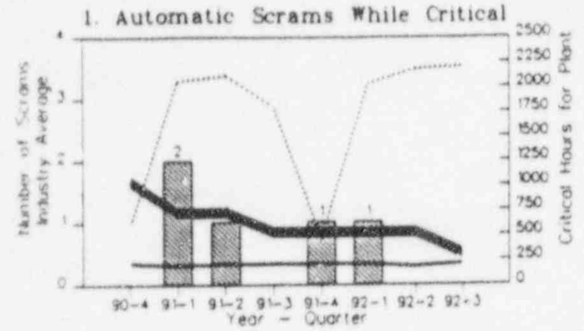


SOUTH TEXAS 2

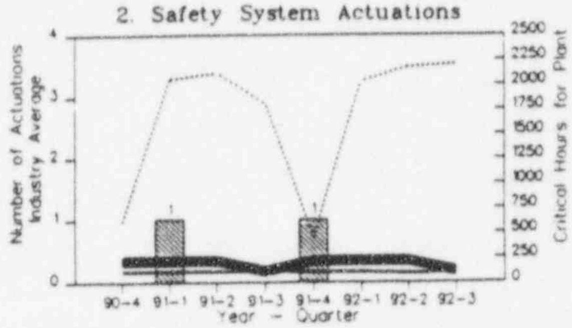
90-4 to 92-3 QUARTERLY DATA

Legend:
- Indicator
- Older Plant 6 Qtr Moving Average
- Critical Hours
- Plant 6 Quarter Moving Average (Long Term Trends)

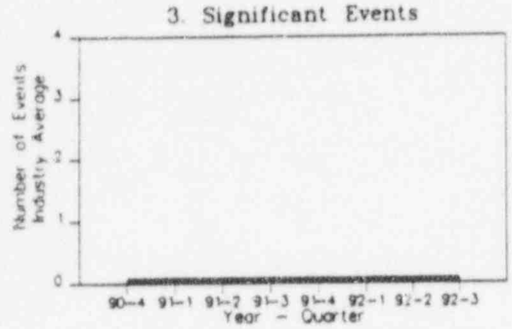
1. Automatic Scrams While Critical



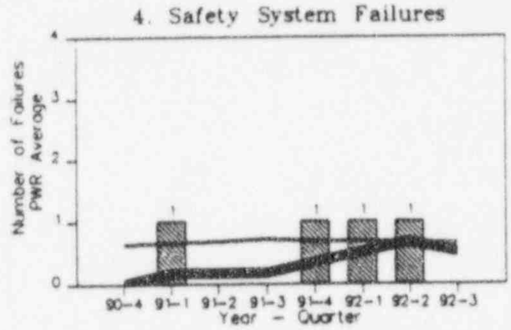
2. Safety System Actuations



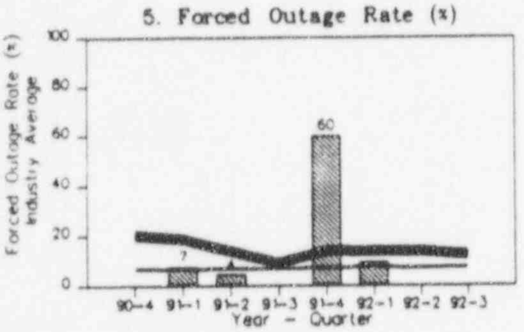
3. Significant Events



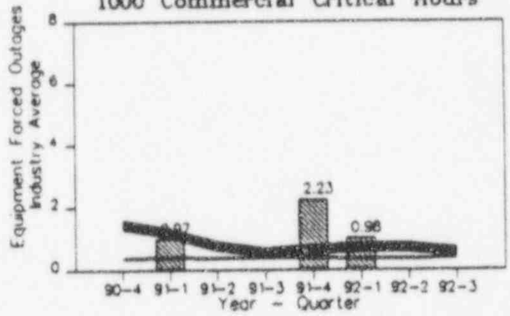
4. Safety System Failures



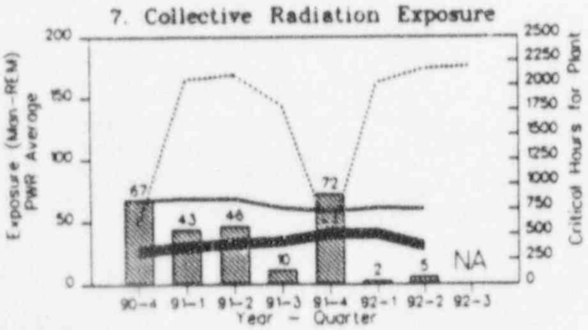
5. Forced Outage Rate (%)



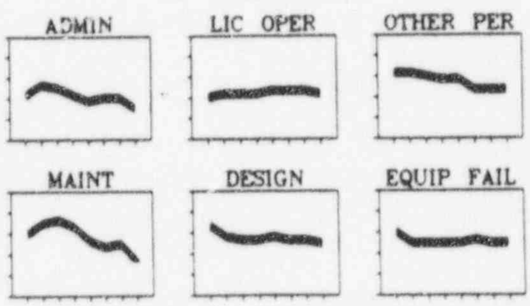
6. Equipment Forced Outages/ 1000 Commercial Critical Hours



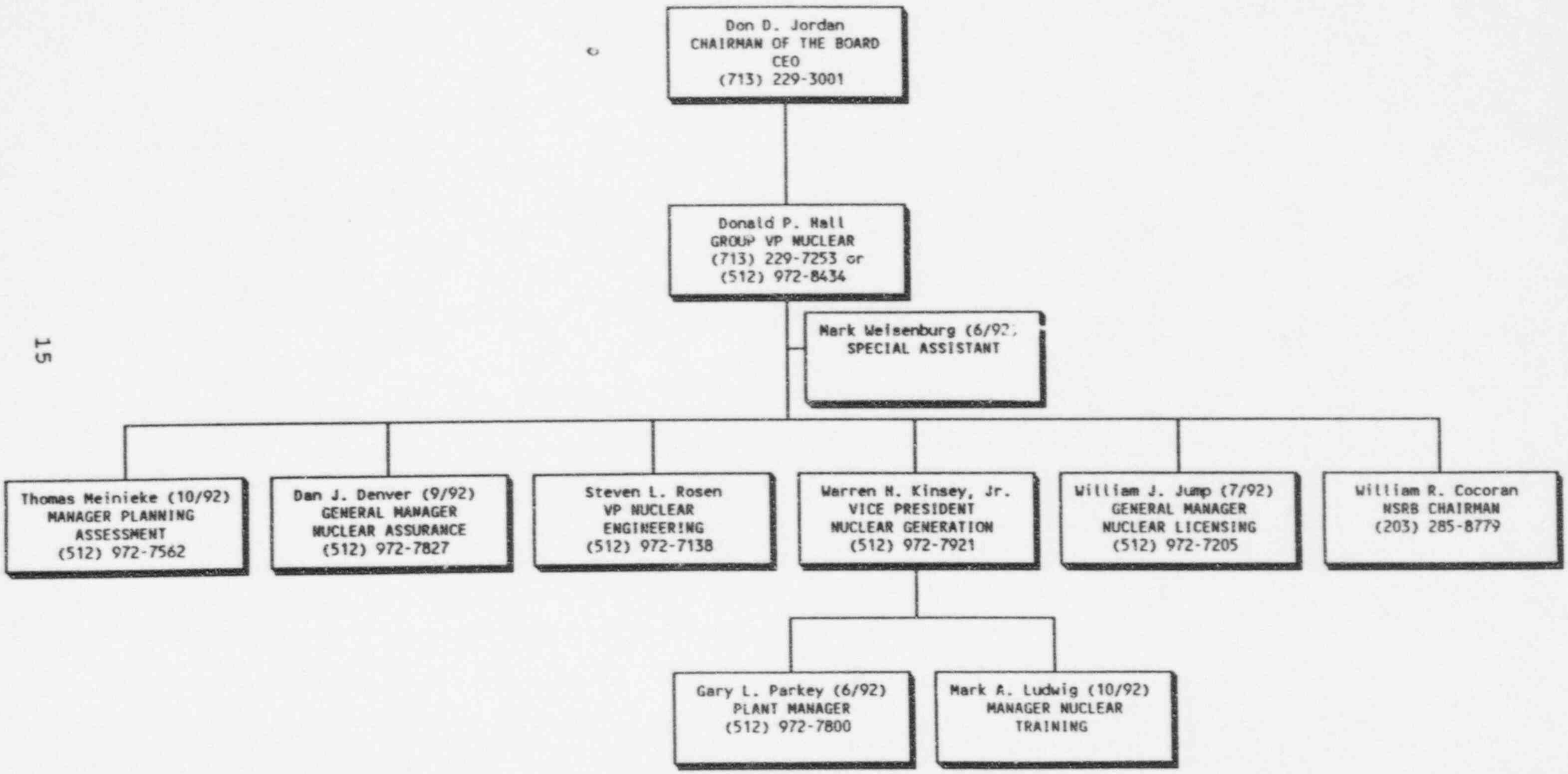
7. Collective Radiation Exposure



8. Cause Codes



HOUSTON LIGHTING & POWER COMPANY
SOUTH TEXAS PROJECT



12/92

ATTACHMENT 1

STATUS SUMMARY OF REGION IV STAFF ACTIONS

Issue 1:	A number of operator workload issues were raised as a result of the diagnostic evaluation at STP. Given the conditions that were prevalent at STP, the design of the facility, and operator workarounds, the scope of responsibilities and administrative work of the operating staff was excessive. For example, the team concluded that operator staffing, although it exceeded TS minimum requirements, was strained in accomplishing the complex tasks for a scenario involving shutdown from outside the control room.
Staff Action 1.(a):	Assess operating staff workload issues at STP and the management actions to resolve them.
Status:	This issue is considered a restart issue. The licensee's Operational Readiness Plan addressed several initiatives to increase staffing and to reduce the administrative workload of the operators. The Region IV inspection in this area is planned to be performed in two segments. The first segment is scheduled for the week of November 1, 1993, and the second segment is scheduled for the week of November 29, 1993.
Issue 3:	A limited review of the fire protection area identified deficiencies at STP associated with: the fire protection computer alarm system and operator training on the system, a large backlog of service requests on fire protection systems, control of transient combustibles in the plant, and fire brigade leader qualification. STP management did not oversee and direct the efforts to resolve the above deficiencies in a timely manner.
Staff Action 3:	Conduct a followup inspection of the fire protection deficiencies at STP.
Status:	This issue includes two restart issues: (1) adequacy of fire brigade leader training and qualifications; and (2) adequacy of the fire protection computers and software, the licensee's success in reducing the number of spurious fire protection system alarms, and other fire protection hardware problems. The first segment of the Region IV inspection of these issues was conducted during the week of October 18, 1993. Preliminary results of this inspection were favorable, indicating considerable progress. A followup inspection will be scheduled prior to unit restart.

D/5

<u>Issue 8</u>: In the transmittal letter forwarding the diagnostic evaluation report, HL&P was requested to review the report and respond within 60 days describing actions they intend to take to address root causes of identified weaknesses.

<u>Staff Action 8</u>: Review and evaluate the licensee's response to the diagnostic evaluation report for completeness. Prepare an appropriate reply for EDO signature.

<u>Status</u>: The licensee submitted its 1994 - 1998 South Texas Project Business Plan on October 15, 1993. The Business Plan and the previously submitted Operational Readiness Plan are intended to address the diagnostic evaluation findings and other performance issues identified by NRC and the licensee. Both are currently under staff review. The STP Restart Panel members discussed the Business Plan in a Panel Meeting that was held on October 28, 1993. In addition, the licensee provided a briefing on the Business Plan in a public meeting at the site on October 29, 1993. A reply to the licensee's submittals is currently being prepared for EDO signature.

59

PM WDR
PD WDR for SCB
AD [illegible]
DD [illegible] for JDR

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

February 17, 1993

South Texas Project

The NRC has announced that the South Texas Project will be the subject of a Diagnostic Evaluation Team (DET). The decision to conduct a diagnostic evaluation at South Texas resulted from concerns and unresolved questions related to the licensee's performance and the effectiveness of improvement programs. The DET will visit the site and licensee's corporate offices during March and April 1993.

Contact:
William Reckley, PDIV-2
504-1314

D/6

PM WDR
PD SB
AD WC
DD JGL

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

February 24, 1993

South Texas Project, Units 1 and 2

South Texas Project, Unit 2 experienced a reactor trip on February 3, 1993 as a result of the loss of an operating main feedwater pump. As steam generator level decreased, auxiliary feedwater was actuated but the turbine driven auxiliary feedwater pump tripped on overspeed. Several days prior to the Unit 2 trip, the licensee had discovered problems with the Unit 1 turbine driven auxiliary feedwater pump related to repeated trips on overspeed. Unit 1 shut down on February 4, 1993 after being unable to resolve the turbine driven auxiliary feedwater pump problems within the Technical Specification's allowed outage time (72 hours). As a result of the issues associated with the performance of both units' turbine driven auxiliary feedwater pumps, the NRC dispatched an Augmented Inspection Team (the AIT's public exit meeting was held on February 24). The licensee investigated the cause of the problems and developed a correction plan for the repair and testing of the turbine driven pumps. Problems identified included inadequate drainage of water from the steam supply lines and minimal operating margins below the overspeed trip.

During the Unit 1 outage, the licensee identified several motor-operated-valves which had been over-torqued and decided to inspect the valves and perform any necessary repairs. The Unit 1 motor operated valve repairs resulted in Unit 2 becoming the lead plant for restoration and testing of the turbine driven auxiliary feedwater pumps. The plan involved performing any necessary repairs on Unit 2, entering Mode 3 to perform confirmatory tests and then shutting down to enter a refueling outage which had been scheduled for late February. The restart of Unit 1 and testing of its turbine driven auxiliary feedwater pump was planned to follow shortly after the completion of the Unit 2 testing. Several successful tests were performed on the Unit 2 pump while the unit was in Mode 4 and Mode 3 was entered on February 22. Turbine governor oscillations were experienced during the first runs of the pump in Mode 3 and the licensee has decided to remove the governor from the Unit 1 pump turbine and install it on Unit 2. The schedules for entering the outage and restarting of Unit 1 have been delayed and a new schedule is being developed.

Contact:
William Reckley
504-1314

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

March 3, 1993

South Texas Project, Units 1 and 2

Both units are currently in Mode 5. Repairs to the Unit 1 turbine driven auxiliary feedwater pump are ongoing. The unit is preparing to go to mid-loop to repair leaking primary manways on two of the four steam generators. The licensee is evaluating the maintenance and operating histories of the other two steam generators to determine whether they will require any maintenance. The current restart estimate for Unit 1 is March 14. The licensee will make a presentation to the NRC addressing auxiliary feedwater pump corrective actions prior to restart.

Unit 2 completed repairs to the turbine driven auxiliary feedwater pump and successful tests were conducted on February 28 and March 1. The licensee considers their actions in response to the Region IV Confirmatory Action Letter regarding the turbine driven auxiliary feedwater pump to be complete. Following completion of pump repairs, the unit entered its third refueling outage.

There will be two enforcement conferences in the Region IV office on March 8. One regards the entry of both units into technical specification 3.0.3 without commencing timely plant shutdowns; the other concerns multiple examples of self-verification weaknesses during surveillance activities. A South Texas Oversight Panel has been established to coordinate NRC inspection activities at the facility due to recent recurrent problems (including corrective action deficiencies, personnel errors, and a high maintenance backlog). The panel will meet in the Region IV office on March 9 to discuss plant status and ongoing inspection activities. The NRR Project Director will attend the enforcement conferences and the oversight panel meeting.

Contact:
Bob Schaaf
504-1356

PM WDR
PD WDR for SCB
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

March 17, 1993

South Texas Project

It has been announced that the current Houston Lighting & Power Nuclear Group Vice President, Donald P. Hall, will be replaced by William T. Cottle. Mr. Cottle had previously been employed by Entergy, Inc. as Vice President - Operations, Grand Gulf. Mr. Cottle will assume his new position at Houston Lighting & Power on April 5, 1993. Mr. Hall will remain with Houston Lighting & Power in a consultant capacity until his retirement in late 1993.

South Texas Unit 1 is currently in a forced outage which began on February 4, 1993. The unit shutdown in accordance with Technical Specifications due to an inoperable turbine driven auxiliary feedwater pump. Other problems encountered during the forced outage include refurbishment of motor operated valve actuators which had been over torqued, repair of primary coolant leaks from steam generator manways, and inoperable toxic gas monitors. The licensee is currently attempting to reduce the backlog of service requests for Unit 1 equipment and has scheduled the unit's return to operation for early April 1993. Unit 2 tripped on February 3, 1993 and, after resolution of concerns related to the operability of the turbine driven auxiliary feedwater pump but not returning to operation, entered a scheduled refueling outage. An NRC Diagnostic Evaluation Team is scheduled to review licensee programs in late March and April 1993.

Contact:
William Reckley
504-1314

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

March 24, 1993

South Texas Project

Both South Texas Project units have remained shutdown since experiencing problems with the turbine driven auxiliary feedwater pumps (TDAFWPs) in early February 1993. Unit 2 completed repairs and testing of the TDAFWP but entered a scheduled refueling outage without returning to power operation. Unit 1 has experienced several additional problems which have delayed the unit's return to operation. It was discovered that potentially excessive torque was applied to several motor-operated valves and resolution required the inspection and refurbishment of the valves. An enforcement conference scheduled for March 25, 1993 will deal, in part, with the licensee's engineering assessments and corrective actions related to these valves. The licensee also observed boron crystals on several steam generator manways which required the licensee to reduce primary inventory in order to perform repairs. The repairs have been completed and the reactor coolant system has been filled. A regional reactive inspection was performed regarding the licensee's programs related to boric acid leakage and several issues and deficiencies were identified. The licensee is currently replacing the power supplies for the toxic gas monitors. The toxic gas monitors have been unreliable and the licensee has identified the power supplies as the most likely cause. In addition to the toxic gas monitors, the licensee has decided to perform maintenance outages for each of the three trains of safety equipment in order to reduce the backlog of service requests. Restart of Unit 1 is currently planned to occur in mid-April. An NRC sponsored public meeting will be held prior to the release of the licensee from a confirmatory action letter and subsequent restart of Unit 1.

Contact:
William Reckley, PDIV-2
504-1314

PM WDR
PD SB
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

March 30, 1993

South Texas Project

Unit 1 remains in Mode 5, Cold Shutdown, with restart scheduled for later in April while Unit 2 is defueled as part of a scheduled refueling outage. The NRC Diagnostic Evaluation Team began its onsite activities on March 29, 1993. An enforcement conference was held on March 25, 1993, to discuss an event related to a motor which was left inoperable for an extended period which affected a valve required to change position during the transfer to hot leg recirculation. An investigation continues into the safety significance of undersized fuses which were installed in electrical distribution panels during the initial plant design. A notice of enforcement discretion was issued on March 30, 1993, to allow closure of the Unit 1 reactor trip breakers. The reactor trip breakers had been opened in accordance with the technical specification associated with the digital rod position indication (DRPI) system which had been declared inoperable in order to perform corrective maintenance. Subsequent problems with the rod control system resulted in the inability to move certain control rods. Repair and troubleshooting of the rod control system required closure of the reactor trip breakers and resulted in the request and approval of the enforcement discretion.

Contact:
William Reckley, PDIV-2
504-1314

PM WDR
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

April 13, 1993

South Texas Project

South Texas Unit 1 remains in Mode 5 in a forced outage which began on February 4, 1993. The licensee is continuing to perform maintenance and surveillance activities on the three trains of safety equipment. In addition, a review of fuse and breaker design requirements is continuing in response to a discovery of an undersized fuse related to the solid state protection system. An extensive test program related to the turbine driven auxiliary feedwater pump must also be completed prior to restart of the unit. A problem related to thermal binding of the control rod drive mechanisms (unable to withdrawal four control rods) is expected to be resolved after the unit increases temperature and reduces stresses that are causing the movable grippers to be stuck in place. The current schedule for restart of the unit is early May 1993. South Texas Unit 2 remains in a refueling outage and activities are being delayed as resources are being dedicated to resolving Unit 1 issues.

An NRC Diagnostic Evaluation Team has completed two weeks of site activities and will return for a third week from April 26-30, 1993. Discussions between the Regional Administrator and NRR Associate Director for Projects have led to the decision to enter NRC Manual Chapter 0350, "Staff Guidelines for Restart Approval." Regional and NRR staff are currently defining the restart action plan and defining other activities associated with the manual chapter. An existing Region IV/NRR oversight panel for South Texas Project has assumed the responsibilities related to the manual chapter restart panel.

Contact:
William Reckley
504-1314

PM NDIR
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

April 21, 1993

South Texas Project Units 1 and 2

In November 1992, INPO placed the South Texas Maintenance Program on probation. INPO policy is to review programs six months following probation, however in the case of South Texas they have decided to defer their appraisal until June (a one month delay). Zack Pate (INPO) made this decision based on the amount of activity that has occurred at the plant since November, including two refueling outages and an NRC Diagnostic Team Inspection. Although the assessment has been delayed, INPO does believe that Houston Lighting and Power has made progress in improving its maintenance program.

Contact:
William Reckley, PDIV-2
504-1314

PM [illegible]
PD [illegible]
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

April 27, 1993

South Texas Project

On April 22, 1993, an enforcement conference was held in the Region IV office between the NRC and Houston Light and Power, the licensee for South Texas Project, Unit Nos. 1 and 2. The purpose of the enforcement conference was to discuss apparent violations regarding the operability of the emergency diesel generators and the auxiliary feedwater system (primarily the turbine driven pump).

The Diagnostic Evaluation Team will complete its inspection on Friday, April 30, 1993, at South Texas Project facility. An exit meeting is planned for the morning of April 30. Region IV and NRR will be represented at this meeting.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

May 4, 1993

South Texas Project

The Diagnostic Evaluation Team completed its onsite inspection activities on Friday, April 30, 1993, at the South Texas Project facility. An informal exit meeting was held on the morning of April 30. Region IV and NRR were represented at this meeting. While there were numerous findings discussed by the team leader, some of the more significant problems that cut across plant disciplines are in the following areas: 1) communications; 2) root cause analysis; 3) resource management; 4) corrective actions; and 5) work control processes. Other findings that are related to these include excessive overtime in the Operations and Maintenance disciplines, weaknesses in the management information systems, and weaknesses in the modification processes.

On April 30, 1993, the licensee announced that Mr. J. Groth will replace Mr. W. Kinsey as Vice President, Nuclear Generation. Mr. W. Kinsey will take a new position within the organization entitled Vice President, Nuclear Support. These changes will take place June 1, 1993.

On May 5 and May 6, 1993, the South Texas Project Oversight Panel will meet to discuss the recent DET findings and its implications in regard to Manual Chapter 0350 concerning restart. NRR and Region IV representatives are working closely to provide a comprehensive program to ensure all aspects of restart coverage are reviewed.

On May 6, 1993, an enforcement conference will be held in the Region IV office to discuss the inoperability of the solid state protection system due to inappropriately sized fuses. NRR will attend this conference.

On May 12 and 13, 1993, Houston Lighting and Power Company's Mr. D. Jordan, Chairman and CEO, and Mr. W. Cottle, Vice President, Nuclear, will visit with the EDO, the Commissioners and the Chairman.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

May 11, 1993

South Texas Project

On May 6, 1993, an enforcement conference was held in the Region IV office to discuss the inoperability of the solid state protection system due to inappropriately sized fuses. NRR attended this conference. After further review, the staff has decided not to take escalated enforcement action since the apparent violation was not safety significant. The Region IV office is still considering a less severe notice of violation.

On May 7, 1993, the Region IV office issued a supplement to the confirmatory action letter, which was dated February 5, 1993, as a result of the Restart Panel meeting on May 5 and 6, 1993. In this supplement, the staff has requested additional information regarding the following items:

* the station problem report process;
* the service request backlog;
* the post maintenance test program;
* outstanding design modifications, temporary modifications and other engineering backlog items (including operability reviews);
* staffing in the operations department;
* status of fire brigade leader training;
* status of fire protection computer system (reliability and functionality);
* management effectiveness in identifying, pursuing, and correcting plant problems, including any plans for independent reviews; and,
* the results of internal restart readiness reviews.

Contact: L. Kokajko
504-1309

PM CEK
PD SB
AD SB
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

May 17, 1993

South Texas Project

The Diagnostic Evaluation Team will provide a briefing regarding its findings and observations at South Texas Project to the Executive Director for Operations on May 27, 1993, at 3:30 p.m.

The Diagnostic Evaluation Team will formally exit in a public meeting with the licensee on June 3, 1993, at 8:30 a.m. at the South Texas Project facility.

The licensee continues to work on hardware and software issues related to the forced outage on South Texas Project, Unit 1, and the refueling outage on Unit 2. Region IV and NRR are following licensee's progress.

Contact: L. Kokajko
504-1309

PM LEK
PD LEK for SCS
AD [illegible]
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

May 25, 1993

South Texas Project

Mr. Thomas Saporito filed a petition pursuant to 10 CFR 2.206 requesting three specific actions:

* Institute a show cause proceeding pursuant to 10 CFR 2.202 to modify, suspend, or revoke the licensee's NRC operational licenses authorizing the operation of the STP nuclear station;

* Initiate appropriate actions to cause the immediate shut down of the two reactors at the STP nuclear station; and,

* Take appropriate enforcement action in the form of issuance of civil penalties against the licensee and/or against licensee management personnel at the STP nuclear station.

Houston Lighting & Power Company, the licensee for the South Texas Project, has estimated that Unit 1 may be ready for restart by the end of May 1993. Unit 2's restart schedule has been moved to August 1, 1993. The licensee continues to work on hardware and software issues related to the forced outage on South Texas Project, Unit 1, and the refueling outage on Unit 2. Region IV and NRR continue to follow the licensee's progress.

The Diagnostic Evaluation Team will formally exit in a public meeting with the licensee on June 3, 1993, at 8:30 a.m. at the South Texas Project facility.

Contact: L. Kokajko
504-1309

PM SB/ra
PD SB
AD
DO

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

June 1, 1993

South Texas Project

Houston Lighting & Power Company, the licensee for the South Texas Project, has advised the staff that it is ready for startup and has requested a pre-startup inspection. (The inspection is the result of the confirmatory action letter, as supplemented.) Currently, this inspection is not scheduled. Region IV and NRR continue to follow the licensee's progress.

On June 1, 1993, the licensee announced that Mr. Lawrence E. Martin will assume the position of General Manager, Nuclear Assurance on June 21, 1993. Mr. Martin will be responsible for quality assurance, quality control and quality performance/SPEAKOUT program. His most recent employer was TVA, where he was the Senior Program Manager for the Vice President of Completion Assurance. Previously, he was employed by the USNRC, Duke Power Company and General Dynamics.

Additionally, the licensee announced that Mr. James J. Sheppard will assume the position of General Manager, Nuclear Licensing on July 6, 1993. His most recent employer was Sequoyah Fuels, where he was its President and CEO. Previously, he was employed by Carolina Power and Light Company as H. B. Robinson Nuclear Plant's General Manager.

The Diagnostic Evaluation Team will formally exit in a public meeting with the licensee on June 3, 1993, at 8:30 a.m. at the South Texas Project facility. (A briefing was held on May 28, 1993, to inform the EDO on the status of the team's findings and observations.)

On May 28, 1993, two severity level III violations with civil penalties were assessed by the USNRC in regard to inspection, repair and operability issues associated with the turbine-driven auxiliary feedwater pump and the emergency diesel generators. The TDAFWP violations were assessed at \$175K and the EDG violations were assessed at \$150K, for a total of \$325K.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

June 9, 1993

South Texas Project, Units 1 and 2

The Diagnostic Evaluation Team formally reviewed its findings in a public meeting with the licensee on June 3, 1993, at the South Texas Project facility. At the meeting, representatives from the other co-owners (co-licensees), the State of Texas, media (print and television) were present, as well as members of the general public. Region IV and NRR attended this meeting.

While there were numerous findings discussed by the team leader, some of the more significant problems (root causes) that cut across plant disciplines are:

* failure of management to provide adequate support;
* ineffective management direction and oversight;
* failure to effectively utilize self-assessment and quality oversight functions; and,
* ineffective root cause/corrective action process.

Mr. Cottle, Group Vice President for Houston Lighting & Power Company, was very supportive of the evaluation and expressed a commitment to correct those issues discussed by the Diagnostic Evaluation Team. Mr. Cottle agreed with the conclusions and observations of the team, although he thought the "resource allocation and utilization" better defined one issue rather than the team's version of inadequate resources and support. The licensee recently announced that the former General Manager, Nuclear Licensing, Mr. W. Jump, will be assigned as an assistant to the Group Vice President to resolve the Diagnostic Evaluation Team's findings and observation.

On June 9, 1993, Houston Lighting & Power Company announced that Mr. T. Cloninger has accepted the position of Vice President-Engineering at the South Texas facility, effective June 28, 1993. Mr. Cloninger, who has experience at Cygna and Entergy, replaces Mr. S. Rosen. Mr. Rosen will assume the newly created position of Vice President-Industry Relations on June 28, 1993.

Contact: L. Kokajko
504-1309

PM WDR. for LEK
PD WDR for SCB
AD TRQ for EGA
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

June 15, 1993

South Texas Project, Units 1 and 2

On June 11, 1993, the Board of Directors for Houston Industries, Incorporated announced that Mr. R. Steve Letbetter will become the President and Chief Operating Officer for Houston Lighting & Power Company, and will also become a Vice President for Houston Industries, Incorporated, effective July 1, 1993. This change will not directly affect the South Texas Project. Group Vice President, Nuclear, Mr. W. Cottle, will continue to report to Mr. Don D. Jordan, Chief Executive Officer and Chairman of the Board of Directors, on matters relating to the operation of South Texas Project. This and various other personnel changes are the result of a strategy planning effort that identified opportunities best pursued through a new structure and personnel changes.

On June 13, 1993, with all fuel removed from the reactor pressure vessel (since last February), Unit 2 experienced a loss of spent fuel pool cooling due to transfer of a 120 vac 1E distribution panel to an alternate power supply for maintenance. After 13 hours, a reactor plant operator (non-licensed) noticed higher than normal component cooling water pump discharge pressure during rounds. It was later determined that two common header isolation valves for the component cooling water system closed during the power surge during the transfer, causing system flow to be isolated from the non-safety loads, which in turn isolated flow to the spent fuel pool heat exchangers. The spent fuel pool temperature rose 19 degrees F (from 99 degrees F to 118 degrees F). No technical specification limits were violated. This was not a valid engineered safety features actuation and no alarm was received in the control room as a result of the temperature increase (the pool temperature did not rise to setpoint of 154 degrees F). However, two control room indications for the two isolation valves closing should have been detected. This event is indicative of poor operating practice (shift turnover and rounds-keeping, insufficient design on common trouble alarm, no precautions in power transfer procedure). As a result, Mr. J. Groth, Vice President, Nuclear Generation, assembled a team to investigate the cause of the event, determine significance, and make recommendations.

The South Texas Project Oversight Panel (Restart Panel) will meet in the Region IV office on June 16, 1993, at 0930 hours. The panel will discuss recent staff inspections, including the Diagnostic Evaluation Team findings and follow-up activities, ongoing work at the site by the licensee, Manual Chapter 0350 implementation status, and various administrative issues. NRR will provide representatives to this meeting.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

June 22, 1993

South Texas Project, Units 1 and 2

On June 17, 1993, the National Nuclear Accrediting Board removed the South Texas Projects maintenance training programs (instrumentation & control, electrical and mechanical) from probationary status. The board found that the licensee had made considerable progress in effectively implementing its accredited training programs.

Mr. D. Sykora has been named the new President and Chief Operating Officer for Houston Industries, reporting directly to Mr. D. Jordan, Chief Executive Officer and Chairman of the Board of Directors, effective July 1, 1993.

Contact: L. Kokajko
504-1309

PM LEK
PD SB
AD Ew
DD Ew JR

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

July 20, 1993

South Texas Project, Units 1 and 2

On July 16, 1993, a public meeting was held at the South Texas Project facility to review the licensee's progress in resolving current issues and to provide the NRC and the public with continuing information regarding plant performance. This is the first in a series of meetings to be held approximately once per month. Region IV and NRR representatives attended this meeting.

This meeting was held to discuss the licensee's approach to analyzing and prioritizing problems noted in the Diagnostic Evaluation Team's report and other self assessments. An overview of the recent management and organizational changes and the South Texas Project Business Plan was presented. Various initiatives in operations, maintenance, engineering, and the corrective action program were presented and discussed. Some of the more significant items mentioned were the maintenance backlog reduction, hiring and training of additional operators (both non-license and license classes), increasing the number of non-licensed operators on shift, moving from 5-shift rotation to 6-shift rotation, improving work control process, and establishing an Operations Work Control Group.

Florence K. Mangan shall assume the position of General Manager, Plant Services, effective August 2, 1993. In this position, she will be responsible for the departments of Information Resources, Project Controls and Budgeting, Plant Projects and Support, Records Management and Administration, and Planning and Assessment. Previously, she held the position of Director, Plant Projects and Support at Entergy's Grand Gulf Nuclear Station, where she was responsible for plant modifications and construction, project management, site business services, information/telecommunications systems, and emergency preparedness.

Contact: L. Kokajko
504-1309

PM [illegible]
PD [illegible]
AD TRQ for EGA
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

JULY 28, 1993

SOUTH TEXAS PROJECT

The City of Austin, Texas, which owns 15% of South Texas Project, Units 1 and 2, is funding an investigation into safety and management problems at the plant. The City of Austin has sued Houston Lighting & Power (the manager of South Texas Project) in the past for mismanagement and has been trying to sell its interest in the plant. The recent financial and management problems revealed by the Diagnostic Evaluation Team have caused concern on the part of Austin City Council members. The investigation is expected to look at recent issues as well as allegations that were made in 1987 during plant construction. These allegations of construction deficiencies and harassment and intimidation issues were investigated by the Government Accountability Project (GAP) which compiled a list of 700 allegations and presented them to the NRC. An NRC special inspection narrowed the list to 213 safety-related allegations and found that all problems had been corrected by the time the NRC completed its investigation. The NRC concluded that the GAP allegations contained no substantive safety issues that would warrant delay in issuance of a full power license and summarized its findings in NUREG-1306, "NRC Safety Significant Assessment Team Report on Allegations Related to the South Texas Project, Units 1 and 2". The GAP has stated that it considered the NRC's investigation superficial and was not happy with the team's findings. CONREX, the contractor hired by the city of Austin, has hired Edna Ottney to head the current investigation. Ms. Ottney is the consultant who headed the original GAP investigation in 1987. The NRC has received one allegation recently requesting the NRC to reinvestigate specific allegations that were closed in 1987 and that the alleger feels were not adequately reviewed. The NRC denied the request, stating that the conclusions set forth in NUREG-1306 are still valid.

CONTACT:
Donna Skay
504-1322

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

August 2, 1993

South Texas Project Units 1 and 2

The Nuclear Generation Management Team at South Texas Project announced a significant nuclear generation reorganization on July 30, 1993, which is designed to focus on operations and maintenance activities and improve communications and individual "ownership" of the plant.

Essentially, a Plant Manager will be assigned to each unit, with three subordinate managers reporting directly to the Plant Manager. The subordinate managers will be the Manager, Plant Operations; Manager, Maintenance; and, Manager, Work Control. Currently, South Texas Project employs only one Plant Manager for both units.

Additionally, each line (craft) employee will be assigned to a particular unit. Support functions will be moved to the Operations Support, Maintenance Support, and Technical Services Departments, which report directly to the Vice President, Nuclear Generation. The current crew leader and supervisor positions in Maintenance will be combined into a single supervisory level. Two supervisors will be assigned to each crew. This will allow a supervisor to alternate weeks between work preparation and work performance, allowing supervisors to spend significant time in the field.

Implementation of these changes is scheduled for the week of August 30, 1993, with the top managers selected first in order to facilitate selecting candidates for other lower positions.

Contact: L. Kokajko
504-1309

PM [handwritten initials]
PD DEH
AD [handwritten initials]
DD [handwritten initials]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

August 11, 1993

South Texas Project, Units 1 and 2

The licensee has placed Unit 1 in mode 4 and is in the process of proceeding to mode 3. This action is required in order to complete the extensive testing (and make any necessary repairs and perform retesting) of the auxiliary feedwater (AFW) pump turbine, which had experienced considerable problems earlier this year. However, the licensee has experienced a variety of mode 3 restraints; e.g. erratic electronic control problem on a steam generator power operated relief valve, motor actuator failure on an injection valve (which has been repaired and is undergoing MOVATS testing), containment airlock problems, and an administrative restraint due to a documentation review as a result of IN 93-55, "Potential Problems with Main Steam Line Break Analysis for Main Steam Vaults/Tunnels." The current plan is to correct all problems and enter mode 3 later today.

Assuming the AFW testing is completed in a timely and satisfactory manner, the licensee plans to defuel Unit 1 and perform a steam generator inspection sometime in September. Unit 2 is already defueled and the steam generator inspection will occur after Unit 1 is completed (in October).

The licensee has made a preliminary response to the Diagnostic Evaluation Team Report in a letter to Mr. Taylor, EDO, on August 5, 1993. The licensee will provide a more detailed response to the team's finding by issuing and implementing an extensive Business Plan, which will cover plant initiatives and improvements, action plans to implement the initiatives and improvements, including the means to sustain them, and necessary resource allocations. (The Business Plan approach was taken by Palo Verde.) Additionally, the licensee is addressing related issues arising out of the Confirmatory Action Letter, as supplemented, and operational readiness issues (e.g., maintenance backlog, engineering tasks and work load).

The governmental representatives of the City of Austin, co-owner of South Texas Project, has requested that Mr. J. Milhoan, Regional Administrator for Region IV, give a briefing on the status of the facility. Although the date has not been determined, it may occur on September 9, 1993. A public meeting at the site is scheduled on September 8, 1993, to discuss the licensee's responses to the Diagnostic Evaluation Team Report and operational readiness at the facility.

Contact: L. Kokajko
504-1309

PM LER
PD BEH
AD TMG for EGA
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

August 16, 1993

South Texas Project, Units 1 and 2

While Unit 1 was in hot standby (mode 3) to perform testing on the turbine-driven auxiliary feedwater (AFW) pump, the licensee observed problems on the "D" main feedwater isolation valve (MFIV) bypass valve. The licensee determined that this occurred as a result of the "D" steam generator main feedwater check valve leaking through, causing excessive pressure (> 847 psid) on the 3-inch MFIV bypass valve (overcoming the closure springs on the valve to maintain the valve closed).

As a result, the licensee declared the MFIV bypass valves inoperable, entered Technical Specification 3.0.3, and ultimately placed the unit in cold shutdown (mode 5). The licensee is communicating with the vendor (Valtek), and with the industry (through Notepad) since this issue may have generic applicability.

The licensee was able to satisfactorily complete a portion of the turbine-driven auxiliary feedwater pump testing program while in mode 3. Although the extensive test program was not fully completed, the licensee decided to defuel Unit 1 and prepare for steam generator inspection, rather than attempt to correct the valve problem and return to mode 3 to complete the testing. Also, the licensee has decided to inspect the steam generators for Unit 2 prior to Unit 1, and is currently preparing for the inspection on Unit 2.

Contact: L. Kokajko
504-1309

PM CGK
PD BAH
AD TRQ for LGA
DO JR

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

August 18, 1993

South Texas Project, Units 1 and 2

On August 18, 1993, Houston Lighting & Power Company announced management changes at the South Texas Project, which are in agreement with the licensee's stated goal of July 30, 1993, to split the organization by unit. This planned reorganization was designed to better focus on operations and maintenance, and to improve communications. (Note that some of the following individuals are new hires from outside the organization.)

Unit 1: Lew W. Myers, Plant Manager
Kenny J. Christian, Manager, Operations
J. Randy Fast, Manager, Maintenance

Unit 2: Gary L. Parkey, Plant Manager (previous manager STP 1/2)
W. M. "Bill" Dowdy, Manager, Operations
Ken Coates, Manager, Maintenance (from Nine Mile Point)

Support: W. Tom Waddell, Manager, Operations Support
Tom E. Underwood, Manager, Maintenance Support
Dave Daniels, Administrator, Corrective Action Group (from ANO)
Kevin Richards, Manager, Outage (acting)
Howard W. Bergendahl, Manager, Technical Services (unchanged)
R. L. "Dick" Balcom, Manager, Security (unchanged)

The licensee will be announcing other management changes later in August, and should have its management team fully in place by then.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

August 26, 1993

South Texas Project, Units 1 and 2

Both units are currently in Mode 6, Refueling.

Unit 1 is in the process of defueling in preparation for steam generator inspections. The reactor vessel head was removed on Sunday, August 22. Two fuel assemblies were off-loaded before refueling activities were suspended due to a malfunction with the logic cards in the refueling machine. The machine was put into manual and refueling activities have been delayed until the cause of the problem is determined.

Unit 2 is defueled and the licensee is currently performing eddy current testing on all four steam generators. The licensee plans on completing Unit 2 inspections on August 29.

Contact:
Suzie Wittenberg
504-1366

PM LEK
PD STS
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

August 31, 1993

South Texas Project, Units 1 and 2

On August 28, 1993, Houston Lighting & Power Company submitted its Operational Readiness Plan for the South Texas Project units in a letter to the Executive Director for Operations. This plan describes: (1) the specific actions being taken prior to the resumption of power operation to improve hardware, programs and personnel performance; (2) the process and criteria by which licensee management will assess readiness to resume power operations; and (3) the method that will be utilized during startup and power ascension to assure safe and reliable return to service. Issues that require continuing action beyond the time of resumption of power operation will be addressed in the South Texas Project Business Plan, which has not yet been submitted.

The Operational Readiness Plan and the Business Plan will address the issues in the NRC's confirmatory action letter, as supplemented, and the Diagnostic Evaluation Team's observations and findings. The Operational Readiness Plan and the Business Plan will be discussed at a public meeting held at the site on September 8, 1993. Region IV and NRR personnel will attend this meeting. Additionally, the NRC's South Texas Project Restart Panel, composed of Region IV and NRR personnel, will meet prior to the public meeting to discuss the licensee's actions to date. The Restart Panel will also discuss the restart checklist (regulatory actions) for the units.

Unit 1 status: Unit 1 personnel began removing fuel assemblies from the reactor vessel, but encountered problems with a logic card on the fuel handling equipment. The licensee is investigating and repairing the equipment. Plant personnel have removed 27 of the 193 fuel assemblies from the reactor vessel to the spent fuel pool in preparation for steam generator inspection. Work on train A systems and components is continuing.

Unit 2 status: Unit 2 personnel are inspecting the steam generators. Plant personnel have decided to plug and stabilize two tubes in steam generator A and steam generator D. In general, the steam generator inspection has gone well.

Contact: L. Kokajko
504-1309

PM CEK
PD [illegible]
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

September 1, 1993

South Texas Project, Units 1 and 2

On August 31, 1993, Houston Lighting & Power Company announced additional management changes that are the result of its plan to have dedicated unit management for each of the South Texas Project units. Moreover, the licensee has stated that the original schedule to implement the new organizational changes has now been delayed until mid-September (from the end of August).

The new management changes are:

Unit 1 Manager, Work Control	John M. Gruber
Unit 1 Division Manager, I&C	Michael P. Murray
Unit 2 Manager, Work Control	Kevin D. Richards
Unit 2 Division Manager, I&C	James D. Ledgerwood

Contact: L. Kokajko
504-1309

PM WDR
PD WDR for SCB
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

September 8, 1993

South Texas Project, Units 1 and 2

Unit 1 completed offloading of the core on September 6, 1993. The offloading had been delayed since late August by problems encountered with the fuel handling machine. The repairs to the fuel handling equipment involved extensive troubleshooting efforts and the replacement of various electronic and mechanical components. Licensee personnel are performing preparations for eddy current testing of the Unit 1 steam generator tubes.

Unit 2 remains defueled following completion of steam generator inspections. One hundred percent of the steam generator tubes were inspected using a bobbin coil probe and selected tubes were also inspected using a motorized rotating pancake coil probe. Several additional steam generator tubes were plugged due to the detected eddy current indications. The licensee is continuing with various maintenance and surveillance activities.

A meeting of the NRC oversight panel for South Texas Project was held on September 8, 1993 at the plant site and was immediately followed by a public meeting with the licensee. The public meeting was held to discuss the licensee's Operational Readiness Plan and Business Plan. These plans were formulated in response to the NRC's confirmatory action letter and concerns identified by an NRC Diagnostic Evaluation. These meetings were attended by Region IV personnel, including John Montgomery, Deputy Regional Administrator, and NRR representatives Jack Roe, DRPW Division Director, and Lawrence Kokajko, Project Manager.

Contact: W. Reckley
504-1314

PM LBK
PD SB
AD E
DO [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

September 14, 1993

South Texas Project, Units 1 and 2

A public meeting was held on September 8, 1993, between Houston Lighting & Power Company and NRC's Region IV and NRR to discuss the licensee's approach to operational readiness. Media representatives were present. It appears that the approach to restart and resolution of long-term issues is acceptable thus far, and the licensee has made some strides in resolving complex managerial and technical issues.

The licensee will implement the "unitization" approach to its organization today (September 14). All plant personnel are assigned to one unit for all work activities on that unit in order to increase communication, instill ownership, and lessen work-related errors.

Steam generator eddy current testing and inspections on South Texas Project, Unit 1 steam generators will commence this week, perhaps as early as September 15. Inspections on Unit 2 steam generators are complete.

Finally, Chairman Selin cancelled his scheduled September 15, 1993, visit to the South Texas Project due to other business-related schedule conflicts.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

September 21, 1993

South Texas Project, Units 1 and 2

On September 20, 1993, Mr. John Groth, Houston Lighting & Power Company's Vice President, Nuclear Generation at the South Texas Project, and his consultant, Mr. Don Davis of PRISM Consulting, Inc., visited the Executive Director for Operations to discuss the status of the South Texas Project. They also met with Division of Reactor Projects III/IV/V, NRR, management.

On September 20, 1993, a public hearing was held in Bay City, Texas, to hear from the general public/plant personnel on issues pertaining to whistleblower activities at the facility. Approximately 20 people spoke at the meeting and only one negative comment was made. On September 21, 1993, the licensee had a chance to make a presentation in a public forum. These meetings are the first of four public meetings being conducted as a part of the reassessment of NRC's program for protecting whistleblowers.

Last week, the licensee decided to organizationally move the Corrective Action Group from the Nuclear Generation (Operations) Department to the Nuclear Assurance Department, which is responsible for the quality assurance activities at South Texas Project. The Corrective Action Group, which had been primarily responsible for root cause analysis, will provide more oversight and assistance functions under this organizational change. Inherent in this change, the general line organizations will be responsible for completing more of the corrective actions within their area of responsibility.

Finally, the licensee has decided to pull 3 tubes from the Unit 1 steam generators after eddy current inspection has been completed. While degradation is not suspected, these tubes will be evaluated to establish baseline data for future use.

Contact: L. Kokajko
504-1309

PM [handwritten initials]
PD [handwritten initials]
AD [handwritten initials]
DD [handwritten initials]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

September 30, 1993

South Texas Project, Units 1 and 2

Unit 1 is currently defueled. The licensee is continuing to perform eddy current testing of steam generator tubes. With inspection of three of four steam generators completed, two tubes have been found with indications which meet the plugging criteria. Licensee evaluation of the test data is continuing. Testing of steam generator D is about 75% complete. Twenty extra tubes in steam generator C were chosen for ultrasonic testing. On September 23, 1993, the licensee provided an event notification report (50.72), because they found a tube (#36-69) in steam generator A with 100% thru wall indication. During the reevaluation of bobbin coil eddy current data (SG tube inspection in 1985), it was determined that the phase angle indicated a 59% weld defect in the tube. The defect was not reported or removed from service as required by TS 4.4.5. The tube will be plugged prior to the unit restart.

Unit 2 is also defueled. After identification of a trend related to inadequate handling of clearance orders, maintenance activities were halted for several hours on September 22, 1993 for management discussions with maintenance personnel. Work was resumed following the counselling sessions.

Contact:
Suzie Wittenberg
504-1366

PM LBL
PD [illegible]
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

October 6, 1993

South Texas Project, Units 1 and 2

A public meeting was held in the Region IV office on October 5, 1993, to discuss operational readiness and restart issues at the South Texas Project facility. Licensee management and representatives from Region IV and NRR were present. In general, the restart issues identified by the licensee were similar to those identified by the staff. The licensee stated that the Business Plan, which will specifically address the Diagnostic Evaluation Team Report, will be issued on October 15. The licensee presented information regarding resolution of open items (managerial, engineering, operations, maintenance), the self-assessment process, the independent assessment process, and the schedule for return to service. The licensee hopes to enter mode 4 on December 9, and achieve criticality on December 14. The next public meeting is tentatively scheduled for October 29 at the South Texas Project.

The South Texas Project Restart Panel met after the public meeting to review the current status of the facility and discuss upcoming inspections. Specifically, an inspection of the licensee's SPEAKOUT Program is planned in October, and the Operational Readiness Assessment Team is scheduled for November. Additionally, a draft South Texas Project Restart Action Plan, which delineates Manual Chapter 0350 items and specific licensee issues, was discussed. The next meeting is tentatively scheduled for October 28.

The licensee has pulled 2 of the 3 steam generator tubes from the unit 1 steam generators. The licensee expects to pull the third tube today. The steam generator inspections have gone well.

Contact: L. Kokajko
504-1309

PM [illegible]
PD [illegible]
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

October 26, 1993

South Texas Project, Units 1 and 2

Unit 1's core reload is now tentatively scheduled to begin on October 29, 1993. The train "C" outage has started on Unit 1. Maintenance activities are continuing on both units.

On October 22, 1993, Unit 1 experienced an overflow while filling the reactor coolant system. The magnetic site glass stuck, indicating a water level far below the actual level, causing the overflow event. This was discovered by a health physicist who noticed water on the floor. This overflow resulted in approximately 2 inches of water (2000 gallons) in the cavity. The event was terminated upon discovery of the overflow condition. An event review team was formed to investigate the event and has tentatively determined that there were several problems. Those problems diagnosed thus far are: calculation used was in error; magnetic sightglass problem (stuck); less than adequate decision to use only one indication in the core defueled configuration; operator training on instrument indication; and communication between control room operator and plant operator.

On October 25, 1993, Unit 1 experienced a small decrease in spent fuel pool level (approximately 1.5 inches) due to a procedural error. When moving water from the recycle holdup tank to the refueling water storage tank, a valve lineup was incorrectly performed when several critical valves which needed to be aligned in a specific sequence were inadvertently not sequenced properly. This caused water to be transferred from the spent fuel pool to the recycle holdup tank. Plant operators noticed the water level decrease and promptly terminated the water transfer. All work activities regarding this equipment were terminated. The licensee is investigating the event to determine all possible causes and corrective actions.

The South Texas Project Restart Action Plan, a comprehensive document for use by the NRC's South Texas Restart Panel in accordance with NRC Manual Chapter 0350, was approved on October 25, 1993. This document outlines those activities necessary for restart of the South Texas units. In regard to restart activities, the licensee has decided to have an independent operational readiness assessment of its recent plant improvement programs. This will enable the licensee to obtain a third-party assessment (from outside nuclear utility personnel) of its strengths and weaknesses prior to restart.

Contact: L. Kokajko
504-1309

PM LK
PD SB
AD Eg
DD J

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

November 2, 1993

South Texas Project, Units 1 and 2

Unit 1 core reload was delayed until November 17, 1993, due to the need to complete additional motor operated valve (MOV) inspections prior to fuel reload. Previous MOV inspections were determined to be not as thorough as once thought, as noted by numerous, albeit minor, quality problems. This led to the determination that re-inspection (and possible corrective action) was necessary. The train "C" outage will be completed prior to Unit 1 fuel reload. Maintenance activities are continuing on both units.

Effective November 1, 1993, Henry H. Butterworth, will assume the position of Unit 1 Operations Manager. Mr. Butterworth has a Bachelor's degree in Nuclear Engineering and has previous experience at the Vogtle station. Ken Christian, the former Operations Manager, will assume the position of Director, Nuclear Generation Projects. This position, considered a developmental assignment, reports directly to John Groth, Vice President, Nuclear Generation.

A meeting will be held on November 8-10, 1993, concerning the licensee's activities associated with NRC Bulletin 88-08 (Thermal Stresses in Piping Connected to the Reactor Coolant System) at the Westinghouse facilities in Pittsburgh, PA. In essence, the licensee maintains that its analysis of piping stresses indicate that it is not necessary to continually monitor and evaluate thermal stresses on piping connected to the reactor coolant system. The NRC staff has hired a contractor to assist in this review.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

November 30, 1993

South Texas Project, Units 1 and 2

On November 21, 1993, the licensee completed the core reload evolution (mode 6, refueling) on South Texas Project, Unit 1. The licensee entered mode 5 (cold shutdown) on November 25, 1993. The train "C" outage was completed on November 28, 1993, and a mini-outage was entered on train "A" to complete modifications to the essential chilled water system to accommodate low heat load conditions. Additionally, the new system walk-down program at South Texas appears to be working effectively as indicated by a discovery of non-obvious discrepancies on one of the emergency diesel generators.

Maintenance activities on South Texas Project, Unit 2 are continuing. The train "A" outage is still in progress.

Due to human performance problems, all MOVATS activities have been suspended on both units. On November 23, 1993, the licensee found that a work crew consisting of both licensee and MOVATS personnel was performing repairs on a safety injection system motor-operated valve with the component energized. The work crew was supposed to be working on a containment spray system motor-operated valve which had been tagged out and de-energized. The plant manager ordered that all work on motor-operated valves cease, and ordered an investigation of the event. Several other problems with the equipment clearance program have been identified. Plant management has discussed this problem with MOVATS and disciplinary action is under consideration. A new procedure for equipment clearance has been prepared, and training is ongoing on the new procedure. Although it is not certain that the new equipment clearance procedure will address all the issues involved in this recent event, the new procedure is considered an improvement. Region IV is monitoring the licensee's investigation and corrective actions.

Contact: L. Kokajko
504-1309

PM CEK
PD SB
AD WDB
DD Z

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

December 7, 1993

South Texas Project, Units 1 and 2

South Texas Project Unit 1 is in Mode 5 and South Texas Project Unit 2 is defueled. Maintenance activities on South Texas Project, Units 1 and 2 are continuing.

The NRC Operational Readiness Assessment Team started the first week of inspection on December 6, 1993. Prior to this, the licensee completed an independent self-assessment (known as the Operational Readiness Oversight Team), which consisted of 21 man-days of plant observations, interviews, and document reviews. The licensee concluded that management practices, in-plant operations, resources, equipment and processes are improving and will support a late-January 1994 start-up. However, the licensee determined that the corrective action program and operating experience review program should receive immediate attention. Another self-assessment period is scheduled for mid-December.

A public meeting was held on December 2, 1993, at the South Texas Project facility to discuss the current plant status and efforts thus far to improve performance. The licensee's presentation covered such topics as operations and maintenance, engineering, safety assessment, operational readiness and the start-up schedule. Additionally, the licensee discussed backlog reduction of station problem reports, service requests, engineering analyses and other related issues. The licensee announced that Mr. Frank Timins has become the Director, Nuclear Security, and Mr. Robert Massey has become the Manager, Generation Support. News media representatives were present.

Vendor test data from the steam generator tubes which were pulled for diagnostic purposes in September suggests there are circumferential cracks at the tube sheet region elevation. This information is very preliminary. A telecon to discuss this topic will be scheduled as soon as the licensee obtains all the information. The staff is considering holding a public meeting (in headquarters) during January to discuss this issue.

Contact: L. Kokajko
504-1309

PM LWK
PD SB
AD EGA
DD JR

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

December 15, 1993

South Texas Project, Units 1 and 2

The NRC Operational Readiness Assessment Team completed its first week of inspection on December 10, 1993. In general, the team expressed concerns with the post maintenance test program, the configuration management program, and the corrective action program. While the licensee has also identified these areas for correction, the team believed that more could have been done to-date and has expressed a tentative concern about restart readiness in January. NRR will send a "quick look" letter to the licensee on these topics in the near future to highlight potential restart problems, which will be preceded by a telephone discussion with the Group Vice President, Nuclear, Mr. W. Cottle. Currently, the team plans to continue the inspection at the site in January.

A telephone conversation was held between the licensee, Region IV and NRR on December 13, 1993, to discuss the status of the four steam generator tubes that were pulled after the recent inspection. (The inspection consisted of 100% bobbin coil and 21% sample MRPC. Four tubes, which had been previously characterized using the MRPC, were pulled, cut into sections and tested for burst strength. The licensee did this to establish a baseline for future inspection and repair activities.) The licensee had not identified any new or unique failure mechanism and appeared to be aggressively pursuing the actual and potential ramifications of the findings and tube burst data. Essentially, the licensee still exceeds Regulatory Guide 1.121 limits on burst strength and is taking steps to ensure safe operation. For example, the licensee intends to modify leakage and steam generator tube rupture procedures, modify administrative controls for detected leakage (lower than the Technical Specifications), provide additional classroom and simulator training for operators on potential events, make enhancements to the chemistry program, and install a Nitrogen-16 monitor to provide early detection of leakage. Additionally, the licensee has submitted a fuel upgrade Technical Specification amendment to lower the T-hot temperature, which is currently under staff review, and plans to submit an amendment for tube sleeving in the future. The staff was impressed with the licensee's discussion and commended the licensee for its proactive work.

An EBASCO contract employee suffered a massive heart attack within the protected area on the evening of December 13, 1993, and was transported to Matagorda County Hospital. The individual died at the hospital.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

December 21, 1993

South Texas Project, Units 1 and 2

Mr. Mike Meyer has been named Assistant to the Vice President for Nuclear Engineering, effective December 14, 1993. Mr. Meyer recently was the Manager, Site Business Services at Entergy's Grand Gulf Nuclear Station.

The "quick look" letter, designed to inform the licensee's upper management of issues identified during the first week of inspection by the Operational Readiness Assessment Team, was issued on December 16, 1993. The licensee will contact the staff in the near future to confirm readiness for the inspection's second phase and its plans to address the issues discussed in the letter.

Contact: L. Kokajko
504-1309

PM [illegible]
PD WDR for SCB
AD [illegible]
DD [illegible]

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

January 5, 1994

South Texas Project, Units 1 and 2

A public meeting will be held at the South Texas Project facility on Friday, January 7, 1994, to discuss the status of the licensee's operational readiness for the restart of Unit 1.

The NRC's Operational Readiness Assessment Team will arrive on-site on Wednesday, January 12, 1994, to begin the second portion of the operational readiness inspection. The licensee's own independent assessment indicates that the plant will be ready to restart in January 1994.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

January 11, 1994

South Texas Project, Units 1 and 2

A public meeting was held at the South Texas Project facility on Friday, January 7, 1994, to discuss the status of the licensee's operational readiness for the restart of Unit 1. The licensee presented information regarding the operations and maintenance areas, engineering accomplishments, operational readiness status, the quality assurance assessment programs and the independent assessment program, and the tentative startup schedule. Approximately six members of the Green Peace Organization attended the meeting. Representatives of the print and broadcast media were also present. The licensee anticipates entry into mode 4 as early as January 19, 1994.

The NRC's Operational Readiness Assessment Team will arrive on-site on Wednesday, January 12, 1994, to begin the second portion of the operational readiness inspection.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

January 18, 1994

South Texas Project, Units 1 and 2

The NRC's Operational Readiness Assessment Team began the second portion of the operational readiness inspection on January 12. At this time, there are no significant issues or concerns identified, although the team is following previously identified issues.

Enforcement discretion was granted by Region IV (with NRR concurrence) on January 15, to enable the licensee to complete post maintenance testing on the digital rod position indication system. The system had to be re-energized to test the system, but could not be energized unless it was operable. The licensee will submit a technical specification change (similar to the new Westinghouse STS 3.0.5) to preclude future items such as this.

Two recent occurrences of equipment clearance problems arose. One instance involved an electrician being shocked, although the electrician suffered no adverse health effects. The electrician began work (cleaning and inspecting) on a motor control center which had power from an old temporary modification. Although the temporary modification was noted, it was not indicated on the clearance form. Additionally, the clearance tag was not in view of the electrician and the electrician did not fully prepare (adequate observation) for the job action. All bus work has been suspended pending further investigation.

The second instance involved a technical specification violation due to an inadvertent boration flow-path during surveillance testing. A valve, which was designated closed (on paper), was in fact open, causing seal injection flow to increase. The operators secured all testing and reported this to the staff.

Finally, the PRA-based technical specification changes for the South Texas Project are in parallel concurrence with DSSA, OTSB and OGC. The goal is to issue the amendments prior to the restart of Unit 1. The status of this action will be reported in this manner until the amendments are issued.

Contact: L. Kokajko
504-1309

PM LBL
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

January 25, 1994

South Texas Project, Units 1 and 2

The NRC's Operational Readiness Assessment Team (ORAT) held an exit meeting on January 21, 1994, at the facility. In general, the ORAT did not find any issue significant enough to become a restart issue, although the team did identify deficiencies and made observations for improvements. Some areas requiring continuing improvement are: configuration management program; correction action program, including station problem report program trending and analysis; technical specification interpretation issues; and, 10 CFR 50.59 screening process modification. The ORAT noticed that the post maintenance testing program had improved. The team also identified good control room operations and personnel qualifications, good morale and attitude which was supportive of plant management, increased plant ownership by the working level staff, and good material condition of the plant. The licensee committed to various actions, some of which are: the implementation of a configuration management action plan; modification of station problem report trending and analysis; reduction of technical specification interpretations; modification of 10 CFR 50.59 screening process, including training; and improvements to operational and maintenance procedures. Media representatives were present.

Licensee management issued a stop-work order on January 22, 1994, due to motor-operated valve work errors that led to a burned-up motor. The licensee augmented its configuration management action plan to assist in resumption of the site activities due to this event. The impact to the restart schedule is unknown, although the licensee will advise the staff of its readiness in a letter on January 28. This letter will inform the staff of the actions taken to address the confirmatory action letter, as supplemented, and its readiness to resume plant operation. The licensee may be able to achieve mode 4 (hot shutdown) by January 28, and may be able to support a public meeting on February 3, with a startup scheduled between February 4 and February 7. However, these dates are speculative at this time.

Finally, the PRA-based technical specification changes for the South Texas Project are in parallel concurrence with DSSA, OTSB and OGC. As of January 25, DSSA and OTSB have concurred on the package. OGC has indicated some concerns with the package, but these are being worked out. The goal is to issue the amendments prior to the restart of Unit 1. The status of this action will be reported in this manner until the amendments are issued.

Contact: L. Kokajko
504-1309

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

June 1, 1994

South Texas Project, Units 1 and 2

Unit 1 Status: Unit 1 is currently operating at 100 percent power.

Unit 2 Status: Unit 2 is currently at 47 percent power. The licensee synchronized to the grid on May 29, 1994, satisfactorily completed turbine trip testing, and returned to the grid on May 30, 1994. The licensee is performing various instrument calibrations and adjustments, flux mapping, and a secondary calorimetric. The licensee will hold at this power level for the next 72 hours to complete an internally-mandated "management readiness review." NRC staff members are currently providing 24-hour shift coverage.

GAO has contacted the staff and requested various documents related to the inspection history at South Texas Project, including documents related to the 1993 DET report and recent restart activities. An entrance meeting between the staff and the GAO auditors was held on Thursday, May 26, 1994. At the meeting, the NRC inspection programs and processes were discussed, and specific questions related to South Texas Project were raised.

Contact: L. Kokajko
504-1309

PM ___
PD ___
AD ___
DD ___

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

February 9, 1994

SOUTH TEXAS PROJECT, UNITS 1 AND 2

Status of Unit 1 Restart

The licensee advised the staff of its readiness to resume plant operation in a letter dated January 29, 1994. This letter stated that it has taken the actions necessary to address the issues identified in the confirmatory action letter, as supplemented. The licensee completed the necessary work activities on Unit 1 which allowed entry into mode 4 (hot shutdown) on February 6, 1994, and entry into mode 4 (hot standby) on February 9, 1994.

Due to emerging technical issues, the licensee requested on February 4 that the public meeting originally planned for February 8 be rescheduled for February 14. Assuming all activities go as expected, the licensee expects to enter mode 2 (startup) on February 15 or 16.

However, certain issues could significantly impact the public meeting and the restart of Unit 1. For example:

Final mode 3 testing of the turbine-driven auxiliary feedwater pump remains to be completed, and unanticipated problems could significantly delay the restart of the unit. Although previous system testing and regional inspections indicate that the system should perform well, an initial unplanned test on February 9 was not successful.

As noted in the quick look letter of January 27, 1994, the Operational Readiness Assessment Team identified three items which must be completed prior to restart. These items were committed to by the licensee. The staff (resident inspector) review has yet to be completed for 2 of the 3 items. The most significant item involved enhancements to the configuration management program.

A startup feedwater pump seal failure, which may have caused some bearing damage, will require pump seal replacement, at a minimum. This job is expected to be completed on Wednesday, February 9.

PM
PD
AD
DD

DIRECTOR HIGHLIGHTS

PROJECT DIRECTORATE IV-2

February 16, 1994

South Texas Project, Units 1 and 2

On February 14, 1994, a public meeting was held at Houston Lighting & Power Company's South Texas Project facility. At this meeting, the licensee discussed its actions in regard to the confirmatory action letter, as supplemented, and its readiness to restart. On February 15, 1994, the Region IV Regional Administrator approved lifting the confirmatory action letter.

On February 14, 1994, the licensee tested a modification to the rod control system that had been installed in response to Generic Letter 93-04. During testing, an irregularity was identified that caused a bank of rods to move inward rather than remain stationary as expected. As a result of discussions with NRR and Region IV, the licensee decided to remove the modification and continue with normal startup procedures.

The licensee plans to enter mode 2 (startup) on February 17, 1994.

Contact: L. Kokajko
504-1309

i0'ala

February 16, 1994

PRELIMINARY NOTIFICATION OF EVENT OR UNUSUAL OCCURRENCE PNO-IV-94-004

This preliminary notification constitutes EARLY notice of events of POSSIBLE safety or public interest significance. The information is as initially received without verification or evaluation, and is basically all that is known by the Region IV staff on this date.

Facility
Houston Lighting & Power Co.
South Texas 1
Wadsworth, Texas
Dockets: 50-498

Licensee Emergency Classification
Notification of Unusual Event
Alert
Site Area Emergency
General Emergency
X Not Applicable

Subject: LIFTING OF CONFIRMATORY ACTION LETTER AT SOUTH TEXAS PROJECT, UNIT 1

On February 15, 1994, after receiving a positive recommendation from the South Texas Project (STP) Restart Panel and other members of the Staff, the Regional Administrator lifted the Confirmatory Action Letter (CAL) for STP, Unit 1. The CAL, initially issued on February 5, 1993, and supplemented on May 7 and October 15, 1993, had required STP to brief the NRC on the results of their efforts to correct hardware and programmatic deficiencies at STP. This briefing, which was open to public observation, was conducted at the STP facility on February 14, 1994. The Regional Administrator's decision was communicated to the licensee in a letter dated February 15, 1994, and stated that the licensee may proceed, in accordance with the facility's license, with the restart of Unit 1.

The licensee is currently conducting control rod testing. Following the satisfactory completion of that testing and completing other required prestartup checks, the licensee plans to start up the unit late on February 16, 1994. The STP resident inspector staff has been augmented with inspectors from the regional office and other Region IV sites and commenced 24-hour observation of control room activities on February 15, 1994. This augmented inspection effort is planned to be maintained through the unit's restart and power ascension.

The state of Texas will be informed.

This information has been confirmed with a licensee representative.

Contact: M. A. SATORIUS
(817)860-8141

~~9402230085~~